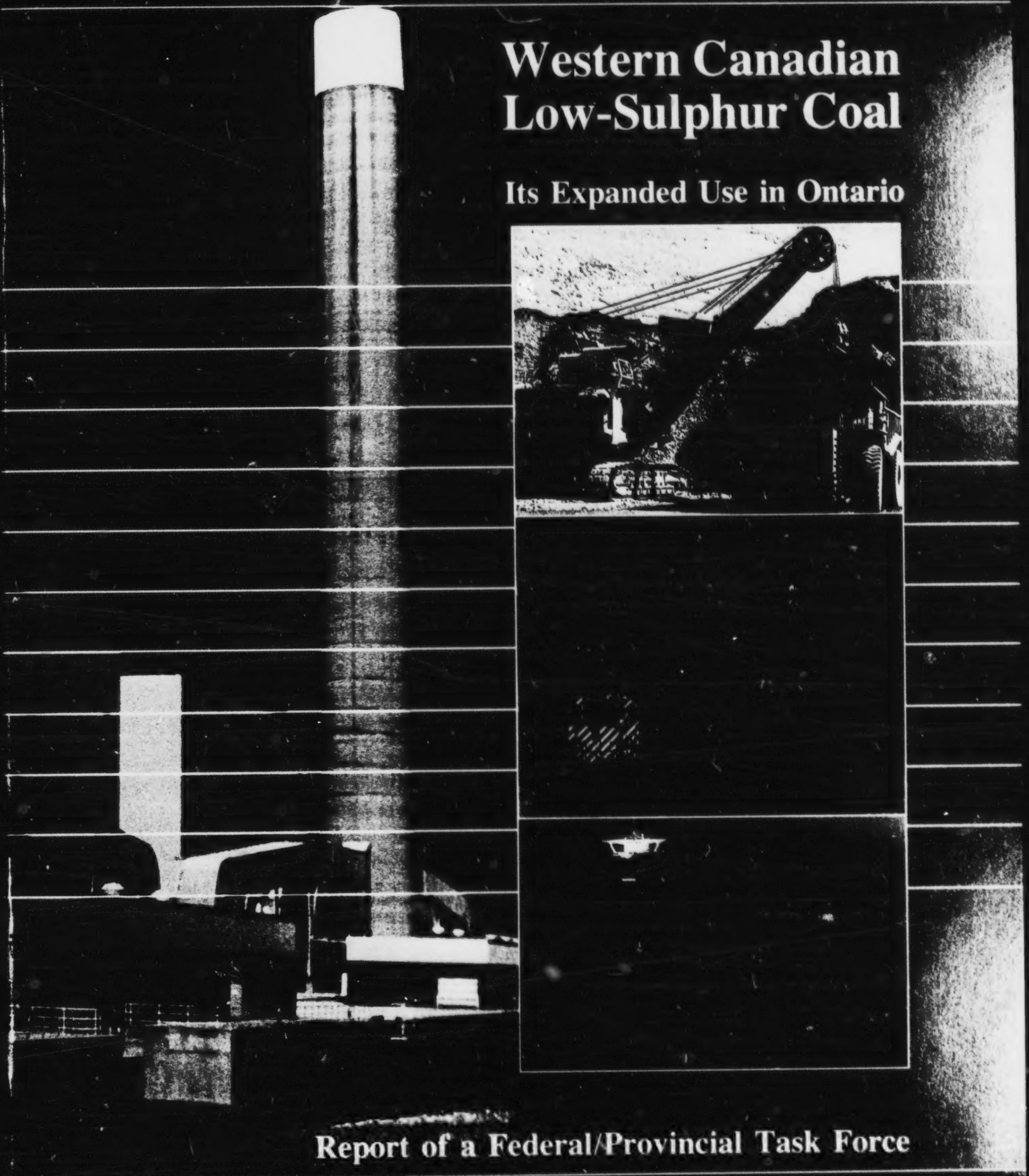
Western Canadian Low-Sulphur Coal

Its Expanded Use in Ontario



Report of a Federal/Provincial Task Force

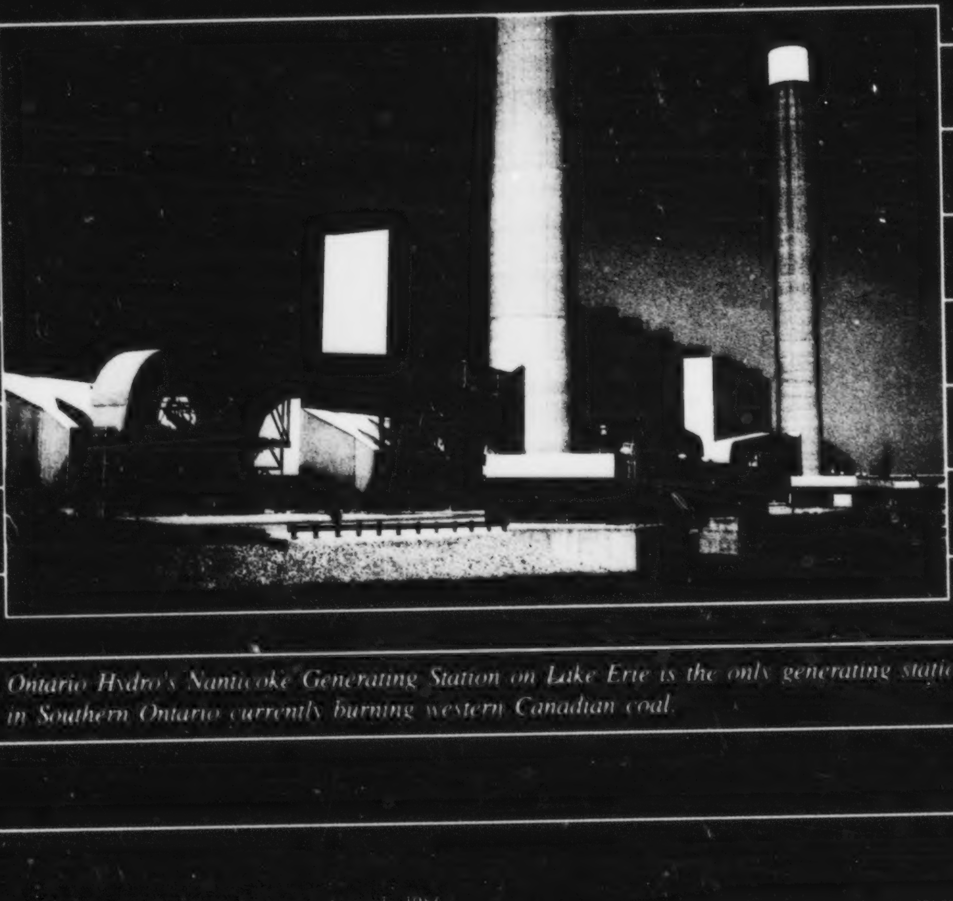
Summary Report

June 1986

Participating Agencies

B.C. Ministry of the Environment
Alberta Environment
Saskatchewan Environment
Ontario Ministry of the Environment

Environment Canada
Transport Canada
Energy, Mines and Resources Canada



Ontario Hydro's Nanticoke Generating Station on Lake Erie is the only generating station in Southern Ontario currently burning western Canadian coal.

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Summary Report

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Introduction

British Columbia, Alberta, and Saskatchewan have abundant reserves of low-sulphur coal. Some of this coal, about 3 million tonnes annually, is now bought by Ontario Hydro for burning at its coal-fired electricity generating stations. The use of western Canadian coal has contributed to reduced sulphur dioxide (SO_2) emissions from these generating stations in recent years, because it has replaced part of Ontario Hydro's major coal supply: medium-sulphur U.S. coal from Pennsylvania and West Virginia.

The commitment by governments to reduce acid rain in Eastern Canada provides a potential market window for more low-sulphur western Canadian coal. Provincial governments in Eastern Canada have agreed to reduce SO_2 emissions to 50 percent of 1980 emission levels by 1994. To accomplish its share of this reduction, the Ontario government has decided that, as part of its overall emission reduction program, emissions must be reduced at Ontario Hydro's generating stations.

Commitment to SO_2 emission control gives impetus to consider expanded use of western Canadian coal.

Recognizing this potential market window, federal and provincial environment ministers recommended in October 1984 that a task force be formed: the federal/provincial Task Force on the Expanded Use in Ontario of Low-Sulphur Western Canadian Coal. The formal statement of purpose of the Task Force is to "assess the comparative costs and benefits of the expanded use of low-sulphur western coal in Ontario including acid rain abatement strategies and economic aspects, taking note of the work already performed by the Alberta/Ontario coal task force."

Federal/provincial Task Force formed to assess costs and benefits.

Based on findings of the Alberta/Ontario task force, this Task Force decided not to examine the smaller industrial consumers of coal in Ontario. The Task Force focussed its assessment on the major consumer: Ontario Hydro.

This investigation is not an assessment of all options open to Ontario Hydro to meet its emission limits. It has been confined to an examination of various combinations in which U.S. coal and western Canadian coal could be used by Ontario Hydro. These combinations of coal use, supplemented by flue gas scrubbers where necessary, enable Ontario Hydro to meet the emission limits from now to the year 2000.

Ontario Hydro will determine how the emission limits will be met, whether by using low-sulphur Canadian or U.S. coal, whether by nuclear power, or by electricity imports. But the national and regional information provided here on expanded use of western Canadian coal should be considered by Ontario Hydro when its course of emission control is being planned.

NOTE: Details of the findings and the associated analyses can be found in the Task Force's Technical Report.

Conclusions

Without emission controls, Ontario Hydro will exceed the provincial limit on acid gas emissions by 1994, when the emission limit of 215 000 tonnes/year [nitrogen oxides (NO_x) and SO_2] comes into effect.

Ontario Hydro can meet provincial emission limits until the year 2000:

- solely with the use of more western Canadian coal;
- by a combination of more western Canadian coal and U.S. coal with flue gas scrubbers; or,
- solely with the use of flue gas scrubbers/U.S. coal.

It is important to note that between now and December 1988, Ontario Hydro is required to submit its method(s) of emission control to the Government of Ontario.

From a National Perspective

The costs of using either U.S. coal with flue gas scrubbers or western Canadian coal are approximately the same.

Using more low-sulphur western Canadian coal has certain national benefits in that it

- creates double the number of Canadian jobs and income over the period from 1985 to 2000;

Using western Canadian coal as part of emission control creates jobs and income throughout Canada.

- spreads the jobs and income equitably throughout the country;
- helps maintain the current diversity of energy options; and
- promotes interregional trade within Canada.

Using U.S. coal with flue gas scrubbers has the potential of

- eliminating the use of western Canadian bituminous coal by Ontario Hydro; resulting, in turn, in a loss of jobs and income in the Canadian mining and transportation sectors; and
- increasing the cost of transporting other bulk commodities within Canada.

Conclusions

From the Perspective for Ontario Hydro

A major factor that could constrain the use of western Canadian coal for controlling acid gas emissions is the cost of burning it in Ontario Hydro's generating stations. To use western Canadian coal as a means of emission control costs about twice as much as emission control with flue gas scrubbers.

The reasons for the difference in cost are

- the high transportation costs for western Canadian coal, and to a lesser extent,
- the costs of station modifications required to burn western Canadian coal.

But western Canadian coal is more costly to Ontario Hydro and Ontario's electricity consumers.

For Ontario Hydro, the use of western Canadian coal only becomes competitive with the use of flue gas scrubbers/U.S. coal when the price of western Canadian bituminous coal is between $65/tonne and $75/tonne. The 1986 price, however, is estimated to be $88/tonne.

From the Consumers' Perspective

By year 2000, the increased cost to Ontario Hydro, because of emission control, will result in an 8-percent price increase for electricity if control is by scrubbers/U.S. coal, and a 16-percent increase if control is by western Canadian coal. However, an expected decline in the real price of electricity is more than sufficient to offset price increases due to emission control by either method.

From the Environmental Perspective

Although they would have the environmental benefit of reducing acid rain, both the use of U.S. coal with flue gas scrubbers and the increased use of western Canadian coal by Ontario Hydro will have other environmental implications. They are not expected to be major constraints, however, given the application of currently available technologies and appropriate government regulations or policies.

From the Perspective of Opportunity

If new nuclear generating stations are brought on line as scheduled, less coal —whether Canadian or U.S. — is required until 1992. An estimated rise in coal demand after 1992 provides an opportunity to increase Canada's share of Ontario Hydro's total coal consumption.

Recommendations

The Task Force urges our Ministers to give early consideration to the following recommendations, so that they may make a timely contribution to Ontario Hydro's emission reduction plan, which is to be submitted to the Government of Ontario by 31 December 1988.

- Pursue the use of western Canadian coal as a potential means of reducing Ontario's acid gas emissions. This presents real economic, employment, and social opportunities and benefits for Canada.
- Pursue ways of making this option economically feasible by encouraging the coal-mining and transportation industries to find ways of reducing the price of delivered western Canadian coal to Southern Ontario to a level that is competitive with that of U.S. coal. Industry should look at specific mechanisms to meet this objective.
- Initiate a cooperative federal/provincial/industrial program to develop and demonstrate advanced coal quality enhancement technologies on bituminous and subbituminous coals, and lignite. Such an initiative should build upon and complement existing programs and be funded as a new part of Canada's acid rain program.
- Encourage Ontario Hydro to maintain its current consumption level of western Canadian coal to ensure that the coal-mining and transportation infrastructures are maintained into the early 1990s, when coal demand is projected to begin a rapid and sustained increase.
- Because the thrust of these recommendations cuts across ministerial responsibilities, environment ministers should encourage their colleagues in departments concerned with economic development, mining, transportation, energy, and employment to discuss expanded use of western Canadian coal in Ontario in their respective ministerial forums.

Needed:

Aggressive government and industry action,

Lower delivered price of coal,

Improved coal quality,

Maintenance of coal mining and transportation infrastructures,

Collaboration among government departments.

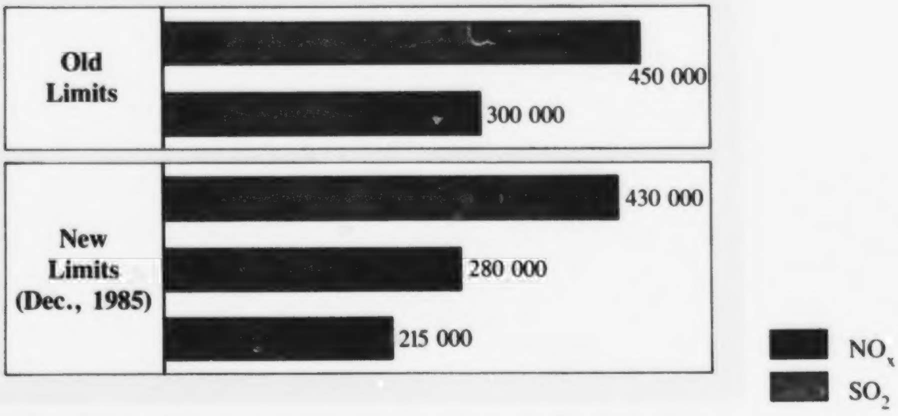
Methodology and Findings

The mandate of the Task Force was to assess the costs and benefits of expanded western Canadian coal use in all sectors in Ontario. However, the assessment here is limited to Ontario Hydro, which burns 85 to 95 percent of all thermal coal consumed in Ontario. Because the smaller industrial users had been examined by the previous Alberta/Ontario task force and because the potential reductions in acid gas emissions through expanded use of western Canadian coal in these sectors are not very significant in the context of Ontario's overall emission reduction program, they are not included in this assessment.

The assessment by the Task Force is linked to coal supply options that will allow Ontario Hydro to meet emission limits until the year 2000. These limits were reduced in Ontario in December 1985 with the introduction of new emission control regulations.

The new regulations reduce the allowable total acid gas emissions in 1994 from 300 000 tonnes/year (an extension of the 1990 limit) to 215 000 tonnes/year, and allowable SO_2 emissions from 260 000 to 175 000 tonnes/year.

Ontario's Limits for Acid Gas Emissions (tonnes/year)



Ontario Hydro's 1985 coal consumption consisted of the following:

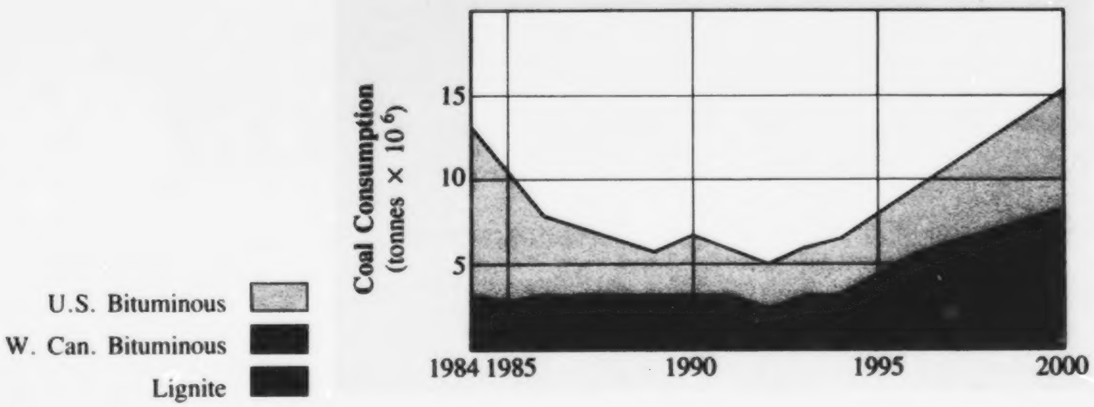
- 7.8 million tonnes of U.S. bituminous coal,
- 2.3 million tonnes of bituminous coal from Alberta and British Columbia,
- 0.8 million tonnes of lignite from Saskatchewan.

Consumption by Ontario Hydro is estimated to drop between 1986 and 1992 if new nuclear power generating units come on line as planned. But the fairly rapid and sustained growth in coal demand thereafter will result in a consumption increase to 14 million – 16 million tonnes/year by the year 2000.

Emission limits will not be exceeded in the late 1980s and early 1990s when anticipated coal demand is low. But in 1994, shortly after the rise in consumption begins and when the new lower emission limit comes into effect, the limit will be exceeded if no emission control is applied.

Methodology and Findings

Estimated Coal Consumption by Ontario Hydro if Western Canadian Coal and U.S. Coal Are Used in Equal Amounts



Method of Assessment

The following options to keep emissions below the regulated limits were examined:

Four coal use options were considered.

- U.S. coal with a sufficient number of flue gas scrubbers to keep emissions below limits,
- combinations of western Canadian coal with U.S. coal and flue gas scrubbers,

(Two combinations were examined: (a) maintaining western Canadian coal at current volumes and (b) western Canadian coal at 50 percent of total coal consumption between 1994 and 2000.)

- sufficient western Canadian coal to keep emissions below limits without using scrubbers.

In considering the overall attractiveness of these coal use options, the following were examined for the period from 1985 to 2000:

- costs to Ontario Hydro,
- costs to Canadian society,
- employment and income generation, and
- environmental implications (including reductions in acid gas emissions).

Assumptions were required in key areas.

In developing this information, assumptions were made in such crucial areas as energy demand and costs of coal mining and transportation. The conclusions and recommendations are subject to the validity of these assumptions. Sensitivity analyses were conducted to determine the effects of variations in selected key areas where assumptions were made. The results presented here are considered adequate for a general policy overview on the expanded use in Ontario of western Canadian coal.

In developing information on costs and benefits, each process of the coal fuel cycle was examined: mining, transportation, and combustion.

Coal Mining

Mining costs contribute 42 percent of the estimated 1986 delivered price of $88/tonne for western Canadian bituminous coal at Ontario Hydro's generating stations in Southern Ontario.

Bituminous Coal. The coal use options examined include western Canadian bituminous coal in quantities approaching 14 million tonnes/year by the year 2000. Bituminous coal supplies in the foothills region of Alberta and B.C. are more than adequate to meet this demand. Supply levels above 4 million tonnes/year require mine expansions in Alberta and B.C., and new mines must be developed for volumes above 9 million tonnes/year. For this analysis it is assumed that coal with the appropriate heat value, ash and volatile contents, and low sulphur (0.3 percent) content can be consistently delivered from these reserves.

Subbituminous Coal and Lignite. It is estimated that both Saskatchewan lignite and Alberta subbituminous coal could be delivered to Southern Ontario at a lower cost per unit of heat content ($/gigajoule) than Alberta or B.C. bituminous coal. The characteristics of these fuels, however, are such that significant use in Southern Ontario power plants would be unlikely, unless the fuels are upgraded or new stations built to accommodate them. Therefore the demand for lignite will likely be limited to the Thunder Bay and Atikokan generating stations in Western Ontario at approximately current levels. This analysis has, therefore, used information on expanded use of western Canadian bituminous coal for estimating costs and benefits. Saskatchewan lignite reserves are more than sufficient to maintain the current level of supply to Ontario of about 1 million tonnes/year throughout the study period without mine expansions or the development of new mines.

Three Types of Thermal Coal

The quality of thermal coal depends on its heat content: the higher the heat content, the higher the quality.

**Bituminous Coal: Heat content:
25 000 – 32 000 kJ/kg.**

**Subbituminous Coal:
Heat content:
19 000 – 25 000 kJ/kg.**

**Lignite: Heat content:
12 000 – 19 000 kJ/kg.**

4554

Coal Transportation

Rail infrastructure is adequate.

The most likely transportation route is by rail to Thunder Bay and by laker to Ontario Hydro's generating stations. The Panama Canal route is a possible alternative route, particularly for B.C. tidewater coal. Slurry pipelines are a possible alternative method of transportation.

The existing rail infrastructure from the B.C./Alberta foothills to the coal terminal at Thunder Bay is adequate to handle increases in rail traffic envisaged under any of the coal use options considered, without additional double-tracking or other modifications. New train sets are required for coal shipments above current levels. The cost of these has been incorporated into the transportation charges for coal volumes above current levels.

Thunder Bay terminal capacity is adequate to 10 million tonnes/year.

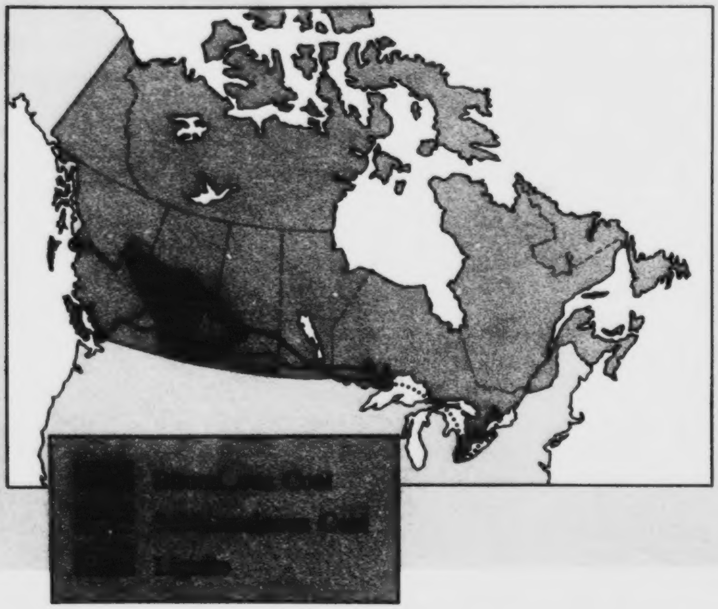
The Thunder Bay terminal can handle up to 10 million tonnes/year; thereafter a second set of unloading equipment and rail extensions would have to be added. Volume-related terminal charges were estimated, taking into account the costs of expansion for higher volumes.

[illegible]

The self-unloading lakers now used to move coal from Thunder Bay to Ontario Hydro generating stations can transport about 3 million tonnes/year. Additional lakers may become available or could be diverted from other uses to carry increased volumes. It is assumed that after coal shipments reach about 9 million tonnes/year, new vessels would have to be constructed. The costs were factored into the transportation charges.

Overall transportation charges account for 58 percent of the estimated 1986 price of $88/tonne for delivered western Canadian bituminous coal to Ontario Hydro's generating stations.

Western Coal Reserves and Canadian Inland Route



Panama Canal Route

— Railways

••••• Vessel Routes

● Coal Terminal

▲ Ontario Coal-Fired Power Plants

Coal Combustion

The combustion stage of the coal fuel cycle concerns all additional or modified equipment required at the electric power generating stations. This includes both modifications to burn western Canadian coal and add-on emission control devices to reduce emissions.

Generating stations require modifications to burn western Canadian coal.

Station Modifications for Western Canadian Coal. Modifications at the three Ontario Hydro generating stations in Southern Ontario (Nanticoke, Lambton, and Lakeview) are required to burn western Canadian bituminous coal at ratios higher than a 50/50 blend with the U.S. coal. Requirements depend on the actual ratio used, but could include modifications to:

- boilers,
- ash handling systems,
- electrostatic precipitators, and
- coal handling and blending facilities.

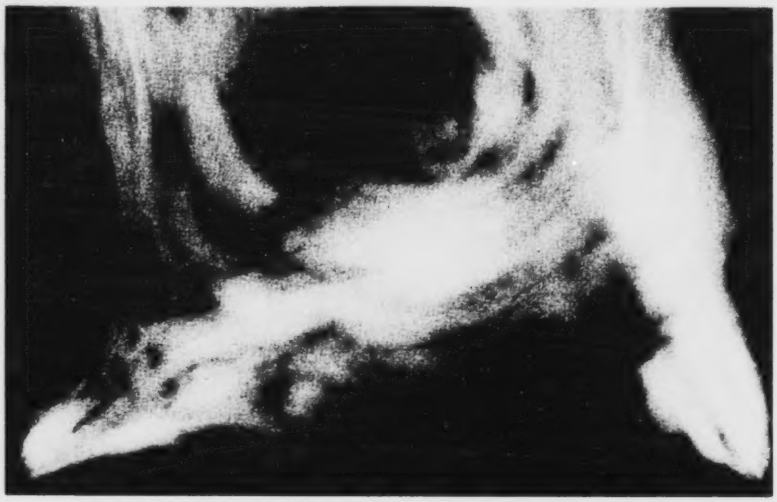
(No station modification costs are included for Lakeview because either a station re-build in the late 1990s or the addition of new capacity capable of burning western Canadian coal has been assumed.)

Extent of possible boiler derating uncertain.

It has been assumed in the base cost analysis that, with these modifications, no boiler derating would occur. The probability of derating remains uncertain — the opinions of boiler manufacturers range from "no anticipated derating" to noncommittal views due to uncertainty about the variability in coal properties.

[illegible]

Emission Control Equipment for U.S. Coal. Emission control equipment (scrubbers) would be needed on twelve 500-megawatt units and three 300-megawatt units by the year 2000 to meet the 215 000-tonne/year limit if the use of western Canadian bituminous coal were phased out. Fewer units would be required for combinations of U.S. coal and western Canadian coal. Both the capital and operating costs of these are included in the cost comparisons.



Cost Comparisons

Perspective for Ontario Hydro. The least-cost method of meeting acid gas emission limits is to install flue gas scrubbers and burn medium-sulphur U.S. coal. The cost of this option is estimated at about $654 million (present value over 1985-2000, including operating costs and capital repayment). The cost of control by expanded use of western Canadian coal alone is almost double that, or $1 280 million.

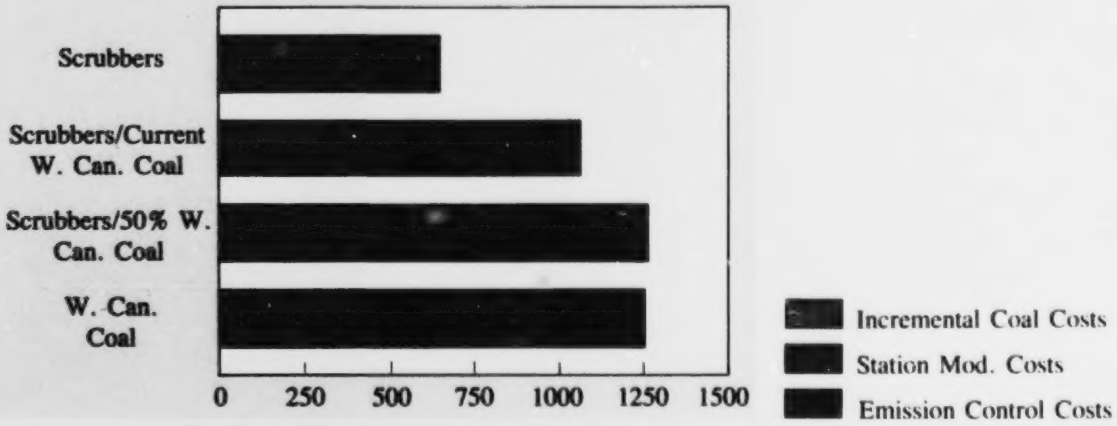
When translated into coal price, this means that the delivered price of western Canadian bituminous coal would have to average about $65/tonne by 1990 before the western Canadian coal option can be competitive with the scrubber/U.S. coal option. This price is about 25 percent lower than the 1986 average delivered price of $88/tonne estimated by the Task Force.

The competitive price is, however, sensitive to several key assumptions:

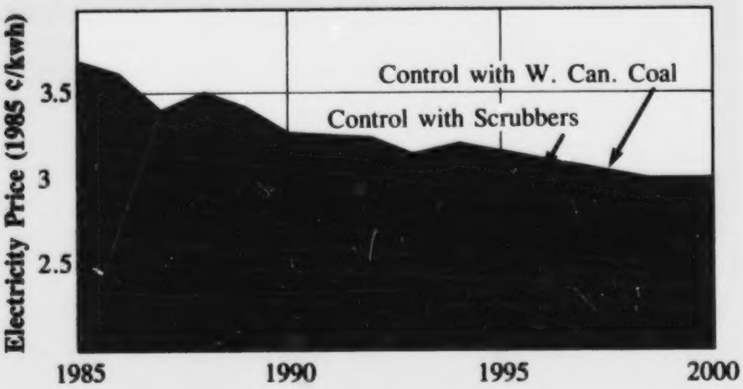
- *Foreign Exchange Rate.* If the foreign exchange rate were to remain at the current high level (instead of dropping to a 20-year average by 1990 as assumed), U.S. coal prices would not decline as rapidly. Western Canadian coal would then be competitive at $75/tonne.
- *Cost of Flue Gas Scrubbers.* If the cost of scrubbers were 20 percent higher than assumed, western Canadian coal would be competitive at $70/tonne;
- *Boiler Derating.* If significant derating were to occur (none was assumed), the competitive price for western Canadian coal would be below $65/tonne, perhaps in the range of $55 to $60/tonne.

Electricity Consumers' Perspective. Based on incremental emission removal costs to Ontario Hydro, the average price for electricity in Ontario would be about 8 percent higher in the year 2000, if emissions were controlled exclusively with scrubbers/U.S. coal; and about 16 percent higher, if emissions were controlled solely by the use of western Canadian coal. That

Cost to Ontario Hydro of Reducing Acid Gas Emissions, 1985 - 2000
(1985 $ millions, present value)



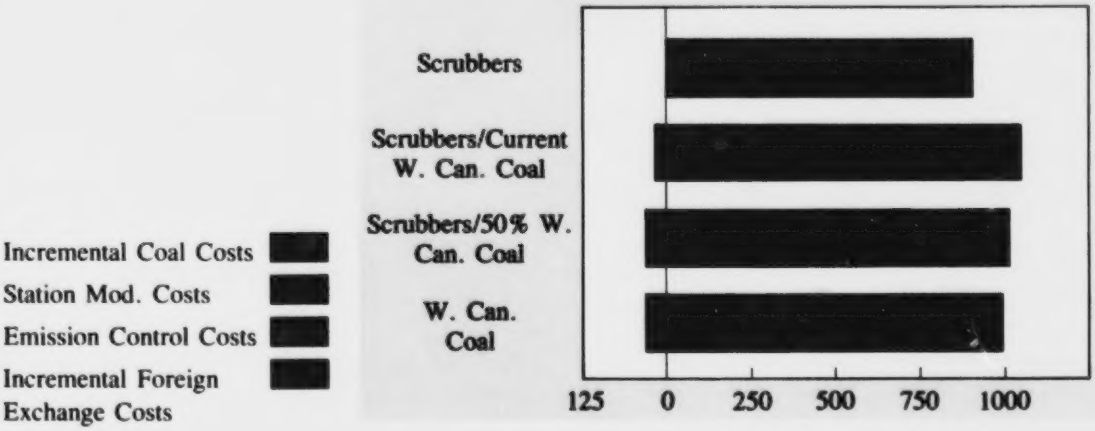
Estimated Price of Electricity in Ontario, 1985 - 2000



means, additional annual costs for an average household are $39 with the scrubber/U.S. coal option, and $79 with the western Canadian coal option. Total additional annual expenditures for electricity by industry, agriculture, households, and commercial/institutional establishments is estimated to be $373 million with the scrubber/U.S. coal option, and $741 million with the western Canadian coal control option.

However, even with these increases over the "no control" situation, overall electricity prices are projected to decline (in constant dollar terms) between now and the year 2000 because of limited capital expenditures for the construction of new generating stations. Although no costs have been estimated, it is anticipated that new capacity will have to be added in the late 1990s to maintain a sufficient system reserve capacity.

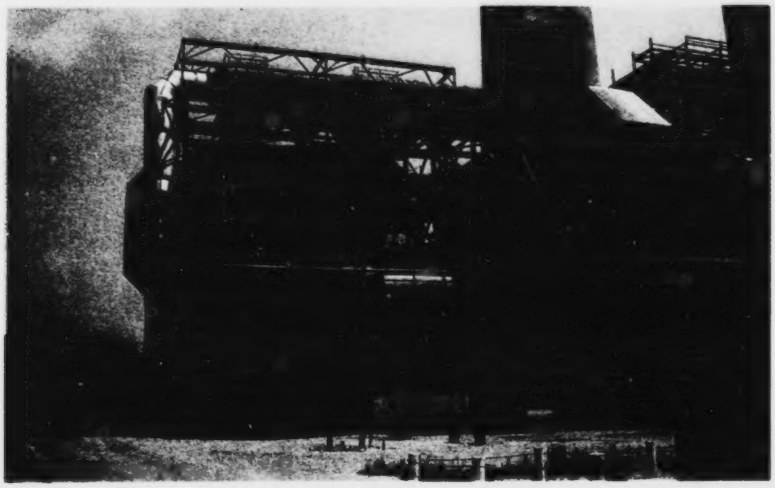
Costs to Canadian Society of Reducing Acid Gas Emissions, 1985 - 2000
(1985 $ millions, present value)

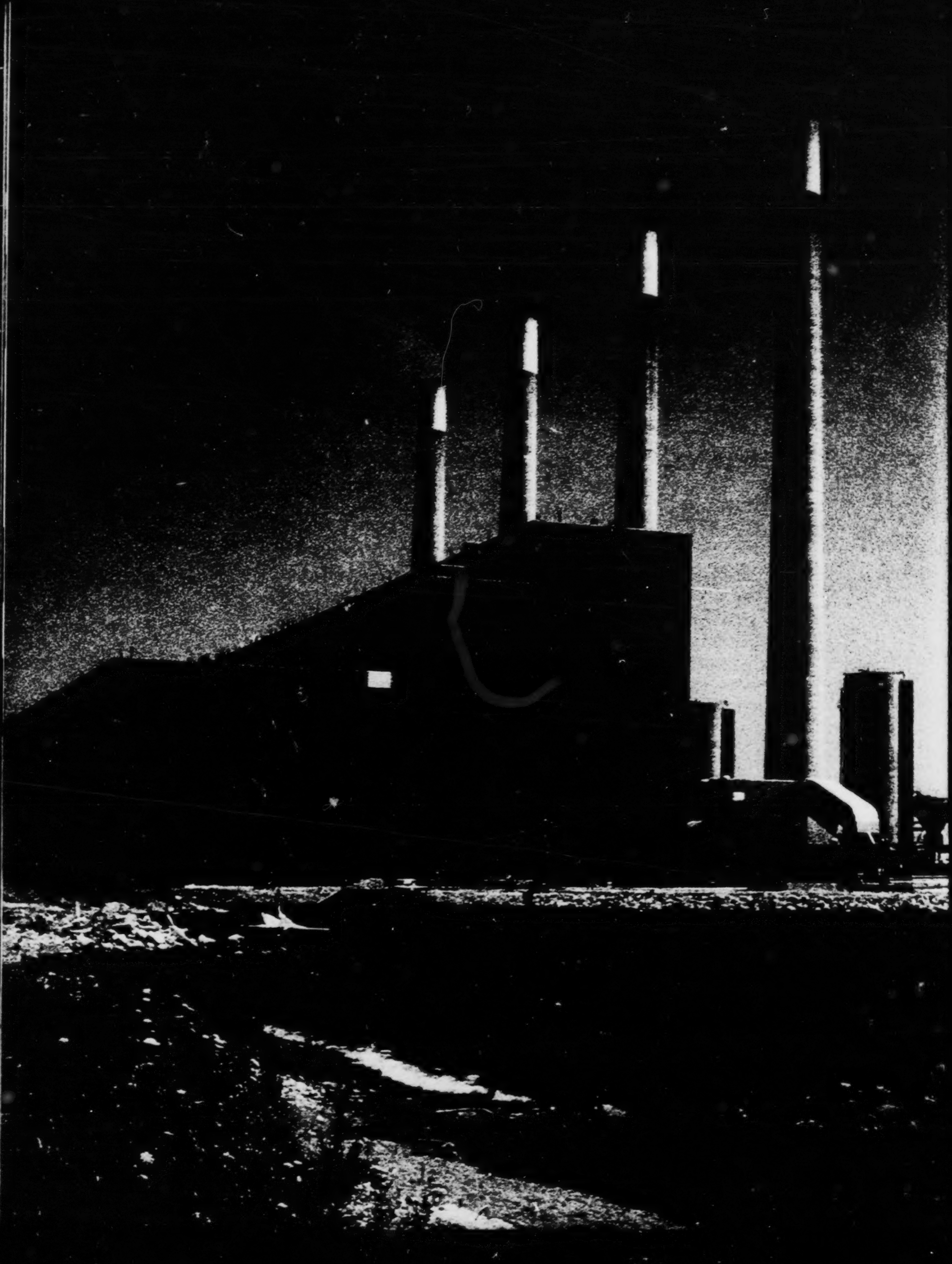


The National Perspective. Although the emission control option using western Canadian coal does not appear to be attractive to Ontario Hydro, it may nevertheless be cost-competitive from the viewpoint of Canadian society. This result is attributed to a number of factors, an important one of which is the exclusion of taxes, profits, some financial charges, and other transfers from the price of Canadian coal. These items represent the transfers between groups within Canada and are not generally considered costs to Canadian society. The social cost (present value) of emission control by scrubbers/U.S. coal are $888 million and by western Canadian coal $950 million. The 7-percent difference in these estimates is within the margin of error for this study, indicating that, from the perspective of Canadian society, the two options are competitive at the 1986 price of $88/tonne assumed for western Canadian bituminous coal.

Sensitivity analysis suggests that the relative attractiveness of western Canadian coal, from this national perspective, would be further enhanced if certain key assumptions were changed.

- *Foreign Exchange Rate.* If the foreign exchange rate were to remain at the current high level (instead of dropping to a 20-year average by 1990 as assumed), the cost, from a national perspective, of reducing acid gas emissions with western Canadian coal would be 14 percent lower than reducing emissions with the flue gas scrubber/U.S. coal option.
- *Delivered Price of Western Canadian Bituminous Coal.* If the delivered price were reduced to $75 and $65/tonne, western Canadian coal would be 3 percent and 18 percent cheaper, respectively, than the flue gas scrubber/U.S. coal option.
- *Cost of Flue Gas Scrubbers.* If the cost of flue gas scrubbers were 20 percent higher than assumed, western Canadian coal would be 10 percent cheaper than the scrubber/U.S. coal option.
- *Boiler Derating.* If significant boiler derating were to occur, western Canadian coal would become uncompetitive, even from a national perspective, with costs rising 20 percent or more above the costs of the scrubber/U.S. coal option.





Effects on Employment and Income

The Task Force estimates of both total Canadian employment and Canadian income generated must be interpreted as maximum values. They are gross estimates because they do not take into account substitution of currently employed workers, the degree to which new jobs are filled by the unemployed, and employment and income which would be generated by alternative investment opportunities.

Employment From Western Canadian Coal Option. Controlling acid gas emissions through expanded use of low-sulphur western Canadian coal is expected to generate about 205 000 person-years of Canadian employment (an average of almost 13 000 permanent jobs) between 1985 and 2000. The employment is relatively evenly distributed among western coal-producing provinces and Ontario. In B.C. and Alberta about 86 000 person-years are projected, concentrated in the mining, rail transportation, and service sectors; an additional 4 000 jobs would be generated in Saskatchewan by transportation and service activities. About 85 000 person-years of employment are expected in Ontario, generated directly from station modification requirements and transportation, and indirectly from the manufacture of transportation and mining equipment and consumer goods. An estimated 30 000 person-years of employment will be generated in other provinces.

Employment and Income Impacts of Reducing Acid Gas Emissions (1985 – 2000)

	Methods of Emission Control		
	Scrubbers	[redacted]	W. Can. Coal
Employment (person-year x 1000)		[redacted]	
Total	104	[redacted]	205
Provincial Distribution		[redacted]	
B.C.	9	[redacted]	37
Alta.	10	[redacted]	49
Sask.	3	[redacted]	4
Ontario	71	[redacted]	85
Other Provinces	11	[redacted]	30
Income (1985, $ millions)		[redacted]	
Total	2421	[redacted]	4060
Provincial Distribution		[redacted]	
B.C.	301	[redacted]	745
Alta.	436	[redacted]	1107
Sask.	129	[redacted]	141
Ontario	1252	[redacted]	1553
Other Provinces	303	[redacted]	514

Further analysis indicates that maximum expanded use of western Canadian coal would generate about 58 000 more person-years of Canadian employment than with *current* levels of western Canadian coal consumption maintained.

Using scrubbers to control emissions creates only 104 000 person-years of employment.

Employment From Scrubber/U.S. Coal Option. Controlling acid gas emissions with scrubbers/U.S. coal exclusively is expected to generate 104 000 person-years of Canadian employment, or an average of 6 500 permanent jobs between 1985 and 2000. This estimate suggests employment generation with emission control by scrubbers will be about half the employment generated under maximum expanded use of low-sulphur western Canadian coal. Differences between the two options are concentrated in B.C. and Alberta, where, with the scrubber/U.S.coal option, the rapid decline and potential phasing-out of coal exports to Ontario result in a significant decline in the employment base in the mining, transportation and service sectors.

Considerable employment is created in Ontario by the manufacture, installation, and operation of scrubbers under the scrubber/U.S. coal option. However, Ontario would experience more employment with the expanded use of western Canadian coal; e.g., manufacture of transportation and related equipment. Controlling acid gas emissions with scrubbers exclusively therefore generates less employment in every province than expanding the use of western Canadian coal does.

Emission control by scrubbers/U.S. coal exclusively would reduce the employment base by about 43 000 person-years below that which would exist if *current* western Canadian coal consumption were maintained between 1985 and 2000.

Western coal would generate twice as much Canadian employment and income.

Corresponding Income Generation. The pattern of Canadian income generation across coal use options is similar to the employment pattern. The scrubber/U.S. coal control option would divert income opportunities to U.S. suppliers. The estimated present value of income generated by the scrubber/U.S. coal option is $2.4 billion over the 1985-2000 period. The comparable figure for expanded use of western Canadian coal, however, is $4.1 billion.

In summary: Controlling acid gas emissions by expanded use of western Canadian coal will safeguard employment and income in coal mining and transportation, employment which would flow to the United States under the scrubber/U.S. coal option.

Environmental Implications

All coal use options examined by the Task Force meet the emission limits. Over the period from 1985 to 2000, both the western Canadian coal option and the scrubber/U.S. coal option reduce total SO_2 emissions by about 1.62 million tonnes. The two intermediate options, where current consumption of low-sulphur coal is maintained between 1985 and 1992 when not actually required to meet emission limits, result in a greater reduction in acid gas emissions — about 1.86 million tonnes over the period from 1985 to 2000.

Increased use of western Canadian coal may result in unfavorable environmental effects during coal mining, preparation, transport, and combustion. Among the more significant effects are:

- temporary land area disruption (mining),
- solid and liquid waste generation (mining and preparation),
- fugitive dust emissions (mining, transportation and combustion),
- particulate emissions (preparation and combustion), and
- nuisance and safety hazards (rail transportation).

Environmental impacts can be effectively controlled.

There are, however, technologies, laws and regulations to control or mitigate many of these environmental effects (e.g., land reclamation). With these provisions, environmental effects are not expected to hinder expanded use of low-sulphur western Canadian coal seriously.

Emerging Technologies

The estimates of cost, employment, and income and the prediction of environmental effects are based on currently available information. During the next decade — before emission limits are reached — technological advances could radically alter the merits of the choice of one option to reduce emissions, over another.

Improving SO_2 Control Equipment

Improvements in SO_2 control equipment are being pursued. With their success, they could reduce the cost of flue gas scrubbing, and hence favour the use of U.S. coal.

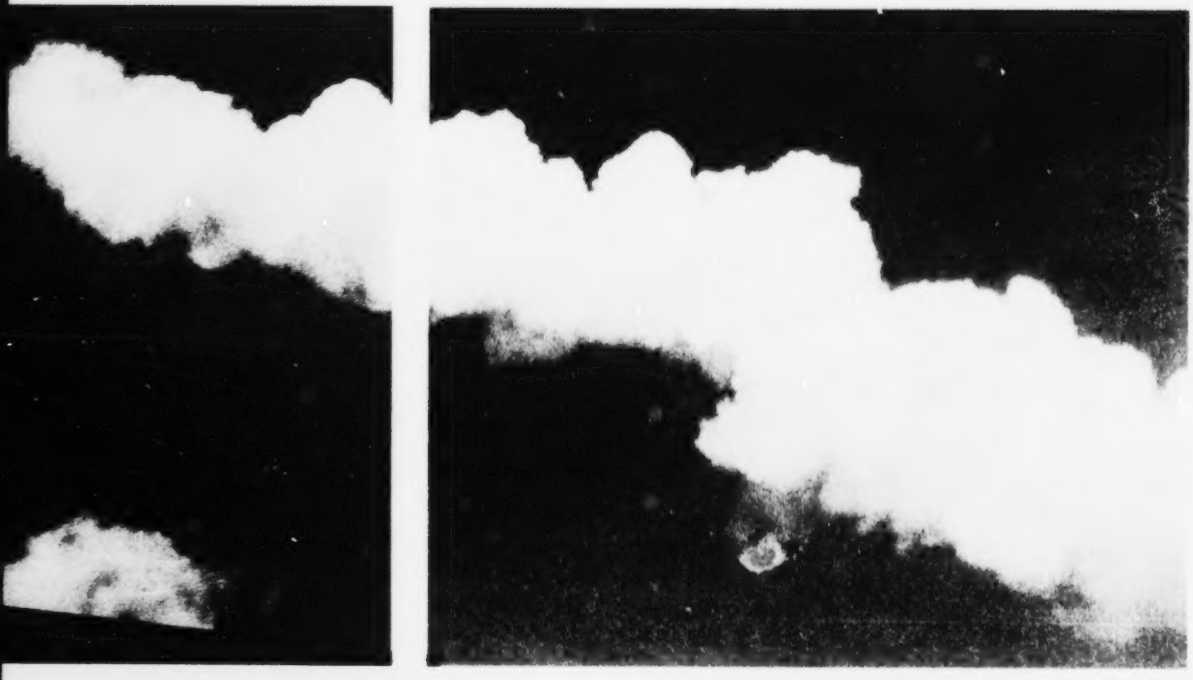
Upgrading Western Canadian Coal

Technologies in coal-upgrading hold promise for enhancing the heat value and other characteristics of western Canadian coal. If these technologies succeed in increasing the quality and reducing the delivered price, the propensity to use western Canadian coal may increase. Higher quality bituminous coal would reduce such combustion-related concerns as station derating. Improvements in the quality of lignite and subbituminous coal combined with additions in either conventional or fluidized bed capacity in the late 1990s may make their expanded use more attractive.

Summary

Expanded use of low-sulphur western Canadian coal by Ontario Hydro offers significant potential benefits to Canada. In addition to reducing acid gas emissions, increased employment and income would result in western and central Canada. Ontario would share in these employment and income benefits. But Ontario consumers would pay more for electricity than they would if Ontario Hydro were to use flue gas scrubbers to control emissions from burning less expensive U.S. coal. U.S. coal has a higher sulphur content than western Canadian coal.

A difference exists between the current delivered price of western Canadian coal and the price that would make it competitive, from Ontario Hydro's perspective, with the scrubber/U.S. coal option. This difference could be reduced by applying new technologies to enhance the quality of western Canadian coal and by reducing charges in the coal-mining or transportation sectors.



Storage piles of western Canadian (left) and U.S. Coal at the Nanticoke Generating Station

Photo Legend

Front Cover	*- Coal Cycle* • *open-pit mining* • *transportation by rail and ship* • *coal combustion*
Title Page	*- Open-pit coal-mining operation*
Page 2	*- Stacker-reclaimer at the Thunder Bay terminal*
Page 6	*- Coal preparation plant for enhancing coal quality*
Page 9	*- Coal removal operations in an open-pit mine*
Page 10	*- Train transporting coal eastward from the western coal fields*
Page 12	*- Coal combustion in the boiler of a generating station*
Page 15	*- Limestone scrubber for removing SO_2 from flue gas*
Page 16	*- Ontario Hydro's Lakeview Generating Station on Lake Ontario*
Page 18	*- Laker delivering western Canadian coal at the Nanticoke Generating Station*
Pages 19/20	*- Emissions from a coal-fired generating station*
Back Cover	*- Stacker-reclaimer at the Thunder Bay terminal*

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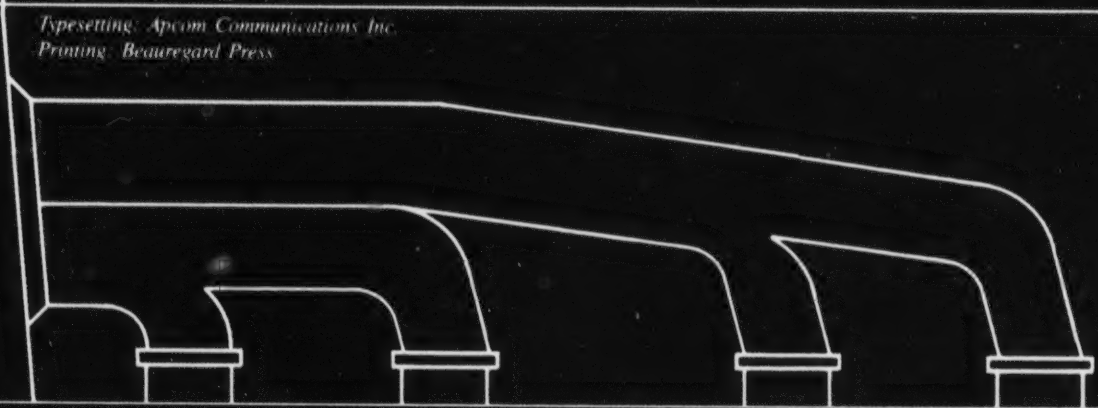
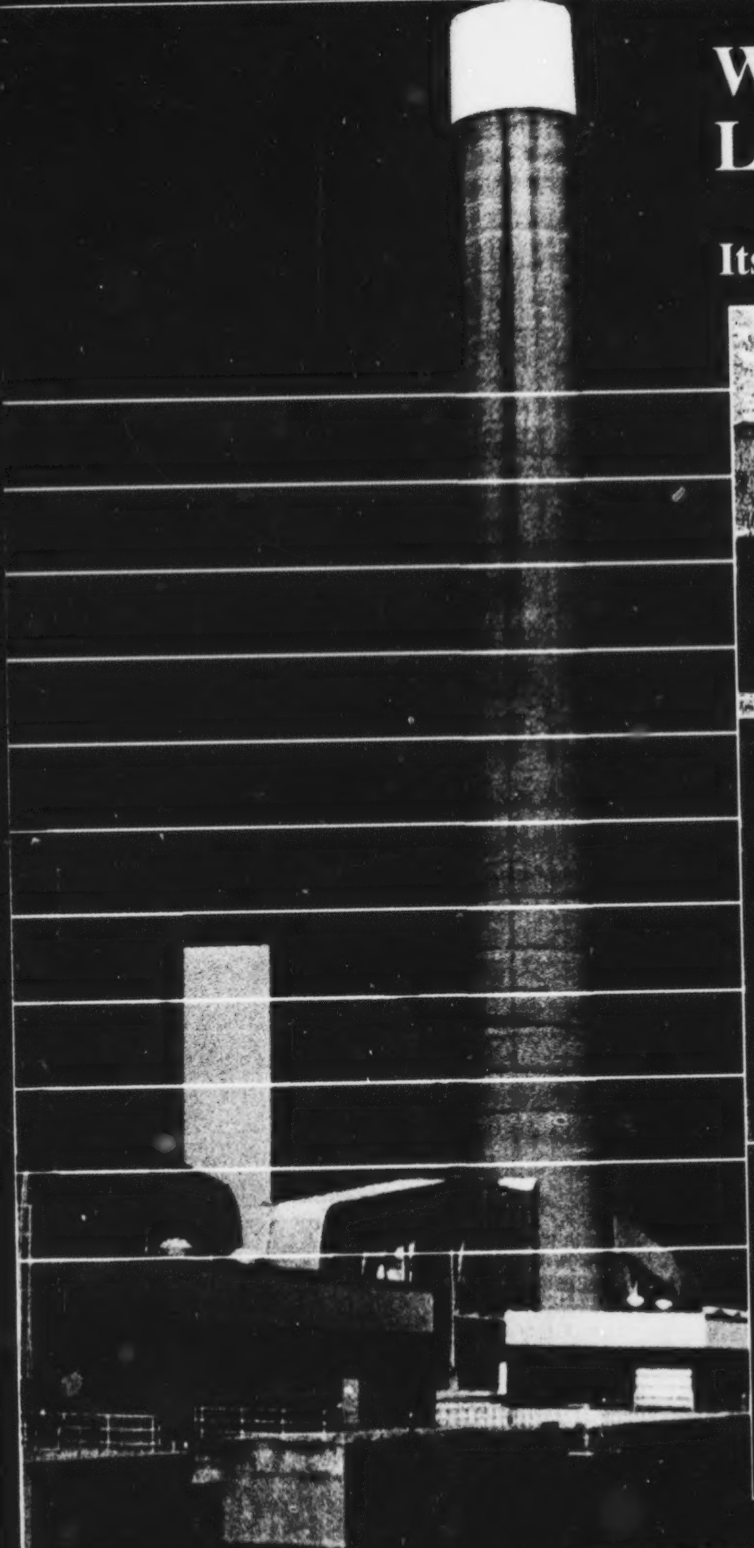
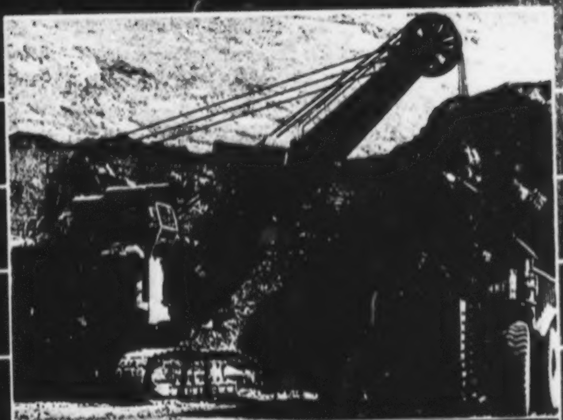


Western Canadian Low-Sulphur Coal

Its Expanded Use in Ontario





Report of a Federal/Provincial Task Force

Technical Report June 1986

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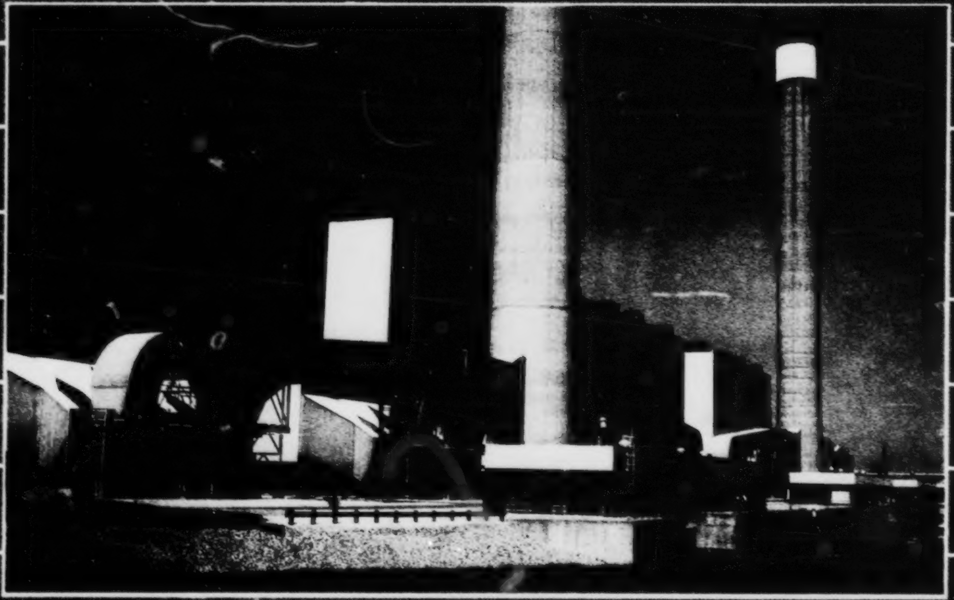
Participating Agencies

B.C. Ministry of the Environment
Alberta Environment
Saskatchewan Environment
Ontario Ministry of the Environment

Environment Canada
Transport Canada
Energy, Mines and Resources Canada



Ontario Hydro's Nanticoke Generating Station on Lake Erie is the only generating station in Southern Ontario currently burning western Canadian coal.

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WESTERN CANADIAN LOW-SULPHUR COAL: ITS EXPANDED USE IN ONTARIO

Technical Report

Federal/Provincial Task Force on Expanded Use in Ontario
of Low-Sulphur Western Canadian Coal

June 1986

ABSTRACT

Low-sulphur western Canadian coal has the potential to decrease acid gas emissions from Ontario coal-fired generating stations. The low-sulphur coal could replace imports from the United States, which have a higher sulphur content.

The western Canadian coal is, however, much further from the Ontario market than Ontario Hydro's current U.S. supply from the eastern states of Pennsylvania and West Virginia. The long transportation distance makes the cost of delivering western coal to Ontario substantially higher than the cost of delivering U.S. coal. However, because of its emission reduction potential, the added costs of the western coal must be compared to the cost of alternative methods of emission control, such as flue gas scrubbers. In addition, mining and transporting larger quantities of Canadian coal has potential benefits in terms of Canadian employment and income, and the general well-being of Canadian mining, transportation and manufacturing industries.

This report presents the technical findings of a federal/provincial task force established to assess the costs and benefits of increasing the use of low-sulphur western Canadian coal in Ontario. In determining the costs and benefits, western coal volumes ranging from 1 000 000 to 15 000 000 t/yr by the year 2000 were considered. Costs and benefits are presented from both a regional and national perspective for the 1985 to 2000 year period. Constraints to the increased use of western Canadian coal, and actions and new technologies that may improve its viability are also identified.

This report forms the basis for a summary report to Federal and Provincial Environment Ministers.

RÉSUMÉ

Le charbon à faible teneur en soufre de l'Ouest canadien offre la possibilité d'abaisser les émissions de gaz acides des centrales électriques alimentées au charbon de l'Ontario. Il pourrait remplacer le charbon importé des États-Unis, à teneur plus élevée en soufre.

Cependant, comme ses gisements sont plus éloignés du marché ontarien (Ontario Hydro) que les sources américaines de l'est des États-Unis (Pennsylvanie et Virginie occidentale), son transport jusqu'en Ontario coûte notablement plus cher. Or, comme le charbon de l'Ouest canadien offre la possibilité de réduire les émissions, ces coûts additionnels doivent être comparés à ceux des méthodes de rechange de réduction des émissions telles que les laveurs de gaz. En outre, l'extraction et le transport de quantités plus grandes de charbon canadien sont prometteurs pour l'emploi et les revenus des Canadiens ainsi que pour la prospérité générale des secteurs des mines, du transport et de l'industrie manufacturière au Canada.

Le présent rapport renferme les conclusions techniques d'un groupe fédéral-provincial de travail, établi pour évaluer les coûts et les avantages de l'accroissement de l'utilisation, en Ontario, du charbon à faible teneur en soufre de l'Ouest canadien. En vue de déterminer ces coûts et avantages, les tonnages mobilisés de charbon de l'Ouest canadien ont été envisagés comme variant de 1 à 15 mégatonnes par année d'ici l'an 2000. Les coûts et les avantages sont présentés selon une optique régionale et nationale pour la période qui va de 1985 à l'an 2000. Les obstacles qui s'opposent à l'emploi accru du charbon de l'Ouest canadien ainsi que les mesures et les techniques nouvelles qui peuvent accroître sa viabilité font également l'objet d'un examen.

Le rapport sommaire, présenté aux ministres fédéraux et provinciaux chargés de l'environnement, s'inspire du présent rapport.

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ACKNOWLEDGEMENTS

Members of the Task Force represent the federal departments of Environment; Energy, Mines and Resources; and Transport; and the provincial ministries of Environment from Ontario, British Columbia, Alberta, and Saskatchewan. Valuable expertise and information was also provided by other provincial ministries, Ontario Hydro, western coal producers, and private firms.

The Task Force was also assisted by Monenco Consultants Ltd. who were contracted to provide a technical assessment of necessary engineering changes (to boilers and coal handling facilities) and their associated costs. The DPA Group Inc. provided socioeconomic impact assessment, social cost analysis, and assembled the report.

LIST OF SYMBOLS AND ABBREVIATIONS

B&W	Babcock and Wilcox
BTU	British Thermal Unit (a measure of heat content)
CAP	capital
Cdn	Canadian
CE	Combustion Engineering
CPI	Consumer Price Index
DCF	discounted cash flow
EPRI	Electric Power Research Institute (U.S.)
ESP	electrostatic precipitator
FBC	fluidized bed combustion
FeS_2	iron sulphide
FGD	flue gas desulphurization
FOB	free on board
GDP	gross domestic product
GS	generating station
GWh	gigawatt hour
ha	hectare
hp	horsepower
kg	kilogram
kJ/kg	kilojoules per kilogram (a measure of heat content)
km	kilometre
kt	kilotonnes
kV	kilovolt
kWh	kilowatt hour
lb	pound
LIMB	lime injection multi-stage burner
m^3	cubic metre
MCR	maximum capacity rating
mm	millimetre
MPa	x 10^6 Pascal
MW	megawatts
NEB	National Energy Board
NO_x	nitrogen oxides
O&M	operation and maintenance
OPN	operations
PA	primary air
PCC	physical coal cleaning
ROI	return on investment
ROM	run-of-mine
SO_2	sulphur dioxide
SPC	Saskatchewan Power Corporation
km^2	square kilometre
t	tonne (metric)
ton	short ton (2000 pounds)
TWh	terawatt hour
U.S.	United States
WCC	Western Canadian Coal
°C	degree Centigrade

SUMMARY

Acid rain and its environmental and economic consequences are major issues facing Canadians today. Evidence of damage to aquatic systems, forests, soils, materials, and human health has stimulated domestic and international discussion.

Within Canada, resource and environment ministries devote considerable attention to identifying, analyzing, and monitoring the effects of acid rain, and determining viable ways in which emission levels can be reduced.

In October 1984, Environment Ministers collectively recommended that a new federal-provincial task force be established to examine the potential to reduce acid gas emissions in Eastern Canada by expanding the use of low-sulphur western Canadian coal. The federal-provincial"Task Force on Expanded Use of Low-Sulphur Western Canadian Coal" was subsequently formed. The formal statement of purpose of the Task Force is to:

"Assess the comparative costs and benefits of the expanded use of low-sulphur western coal in Ontario, including acid rain abatement strategies and economic aspects, taking note of the work already performed by the Alberta-Ontario Coal Task Force."

Members of the Task Force from the federal government represent the departments of Environment; Energy, Mines and Resources; and Transport. Members from the provincial governments represent Ministries of Environment from Ontario, British Columbia, Alberta, and Saskatchewan. The Task Force is chaired by Environment Canada.

Findings from a previous Alberta/Ontario task force on the potential of expanded use of western Canadian coal provided the starting point for the present federal/provincial task force.

This technical document presents the analyses undertaken by the federal/provincial Task Force and forms the basis of a summary report to Ministers in which broader considerations are addressed, and conclusions and recommendations made.

On the basis of the Alberta/Ontario Task Force findings, the present Task Force focussed its investigations on expanded use of western coal by Ontario Hydro. The utility is the largest single buyer of thermal coal in Ontario and is required (by Ontario legislation) to reduce annual acid gas emissions from control levels of 430 kt/yr to 280 kt/yr by the year 1990, and to 215 kt/yr by the year 1994.

Ontario Hydro is faced with a number of options for meeting this limit. In the short term, the utility will likely continue its current program to reduce acid gas emissions by replacing coal-fired generation with nuclear power. Without further action, however, emissions will probably exceed their new limits by 1994. At present, the most common method of reducing acid gas emissions is wet scrubbing, hereafter referred to as flue gas desulphurization (FGD). Although fully proven in the U.S. and other countries, no FGD systems are currently installed at Canadian power plants.

Alternatively, U.S. coal of 2.2% sulphur could be replaced by low-sulphur (0.2% to 0.5%) western Canadian bituminous coal. This substitution avoids the cost of FGD systems but increases delivered coal costs to Ontario Hydro. In assessing the costs and benefits of expanded use of low-sulphur western Canadian coal as an alternative to FGD, the Task Force selected four (of many possible) coal use scenarios. One scenario - the FGD Control scenario - assumes new limits will be met only by FGD with western Canadian coal phased out. Another scenario - the Western Canadian Coal (WCC) Control scenario -assumes the limits will be met only by increased use of western coal (no FGD). Two intermediate scenarios - the Status Quo and Mixed Controls scenarios - assume acid gas emissions limits are met through a combination of FGD and western Canadian coal.

In considering the overall attractiveness of the coal use scenarios, the following are examined through the 1985 to 2000 year period:

- costs to Ontario Hydro;
- costs to Canadian society as a whole;
- employment and income generation; and
- environmental implications (including reductions in acid gas emissions).

In addition, emerging technologies that could improve the future attractiveness of western Canadian coal are discussed.

The Task Force's findings are to be regarded as indicative only. They are intended to provide a fuller understanding of the potential for expanded use of western Canadian coal for future discussion. The estimates, therefore, are sufficient for general policy overview, but not for definite conclusions on the use of western Canadian coal. Many assumptions are used to estimate coal price profiles and other conditions and costs. Results could vary significantly with changes in these underlying assumptions.

General Findings

The general findings of the Task Force are:

1. Ontario Hydro's demand for coal (U.S. and western Canadian) will decline until 1992 when the last generating unit at the Darlington nuclear station comes on line, then coal demand is projected to rise by 14 x 10^6 to 16 x 10^6 t/yr by the year 2000. These projections could be significantly altered by different assumptions on electricity demand, nuclear unit availability, and electricity imports.

2. Meeting emission limits through the use of western Canadian coal alone will require production of about 15 x 10^6 t/yr (1 x 10^6 t/yr of lignite and 14 x 10^6 t/yr bituminous coal) by the year 2000. Bituminous coal supplies in the foothills region of Alberta and British Columbia are more than adequate to meet this demand. It is assumed for this analysis that coal with the appropriate calorific value, ash and volatile contents, and low (0.3%) sulphur content can be consistently delivered from these reserves.

3. It is estimated that both Saskatchewan lignite and Alberta subbituminous coal could be delivered to southern Ontario at a lower cost per unit of heat content ($ per million kJ) than Alberta or B.C. bituminous coal. However, the characteristics of these fuels are such that, unless they are upgraded or new stations are built to accommodate them, significant use in southern Ontario power plants would be unlikely. Unless new capacity designed to burn lignite is built in southern Ontario in the late 1990s or a beneficiated lignite product is developed, supply will likely be limited to Thunder Bay and Atikokan generating stations at approximately current levels. (The current analysis has, therefore, concentrated on western Canadian bituminous coal.)

4. Bituminous coal supply levels above 4 x 10^6 t/yr require mine expansions in Alberta and B.C., and new mines must be developed for volumes above 9 x 10^6 t/yr. Saskatchewan lignite reserves are more than sufficient to maintain the current level of supply to Ontario of about 1 x 10^6 t/yr throughout the study period without mine expansions or new mines.

5. The most likely transportation route is by rail to Thunder Bay and by laker to Ontario Hydro generating stations. Both the Panama Canal route (particularly for B.C. tidewater coal) and slurry pipelines are possible alternatives.

6. The existing rail infrastructure from the B.C./Alberta foothills to the coal terminal at Thunder Bay is adequate to handle increases in rail traffic envisaged under any of the four coal use scenarios without additional double-tracking or modification. New train sets are required for coal shipments above current levels.

7. The Thunder Bay terminal can handle up to 10 x 10^6 t/yr, after which a second set of unloading equipment and rail extensions would have to be added.

8. The self-unloading lakers now used to move coal from Thunder Bay to Ontario Hydro generating stations can transport about 3 x 10^6 t/yr. Additional lakers may become available or could be diverted from other uses. It is assumed that after coal shipments reach about 9 x 10^6 t/yr new vessels would have to be constructed.

9. Modifications at the three Ontario Hydro generating stations in southern Ontario (Nanticoke, Lambton, and Lakeview) are required to burn western Canadian bituminous coal at ratios higher than a 50/50 blend with U.S. coal. Requirements depend on the actual percentage used, but could include modifications to:

   - boilers;
   - ash handling systems;
   - electrostatic precipitators; and
   - coal handling and blending facilities.

   No station modification costs are included for Lakeview because either a station rebuild in the late 1990s or the addition of new capacity capable of burning western Canadian coal has been assumed.

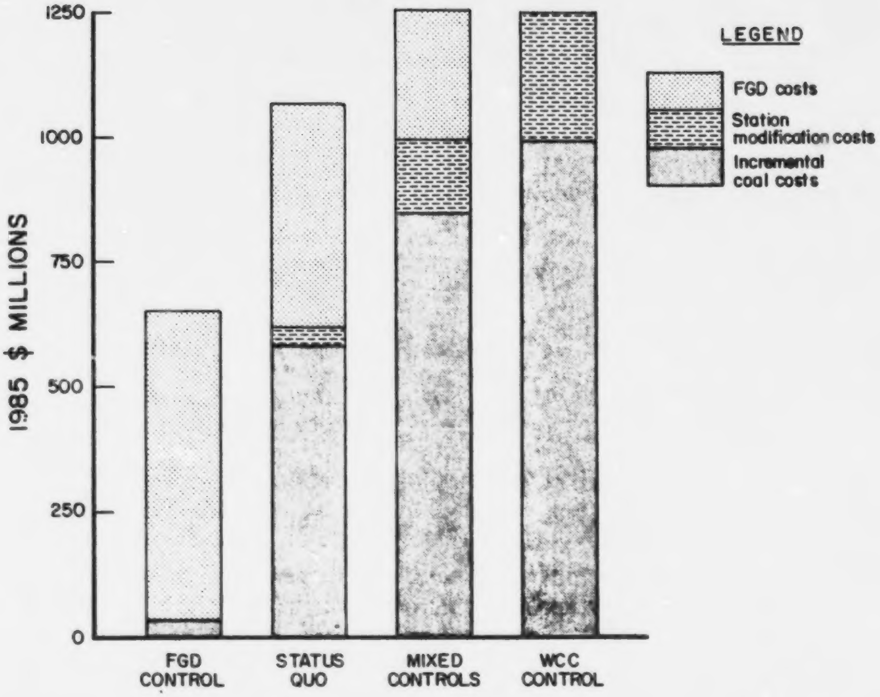
10. Emission control equipment (FGD) would be needed on twelve 500 MW units and three 300 MW units by the year 2000 to meet the 215 kt limit if use of western Canadian bituminous coal is phased out.

Cost Comparisons

From Ontario Hydro's perspective, the least cost method of meeting acid gas emission limits is to install FGD and burn medium-sulphur U.S. coal. The cost of this option is estimated at about $654 million (present value over the 1985 to 2000 year period, including operating costs and capital repayment). The cost of control by expanded use of western Canadian coal alone is almost double ($1280 million).

Sensitivity analyses indicate that, if the Canadian/U.S. exchange rate remained at the February, 1986 level and did not drop to the 20 year average as projected, the western Canadian coal option may be viable at a bituminous coal price of $75/t. If the exchange rate does fall, the delivered price of western Canadian bituminous coal would have to average about $65/t by 1990 for the two options to be competitive. This is about 25% lower than the average price of $87.75/t estimated by the Task Force for 1986. If, however, higher percentages of western Canadian coal cause boiler derating, the cost differential between the two options would widen.

Based on incremental emission removal costs to Ontario Hydro, consumers would pay about 8% more for their electricity in the year 2000 if emissions were

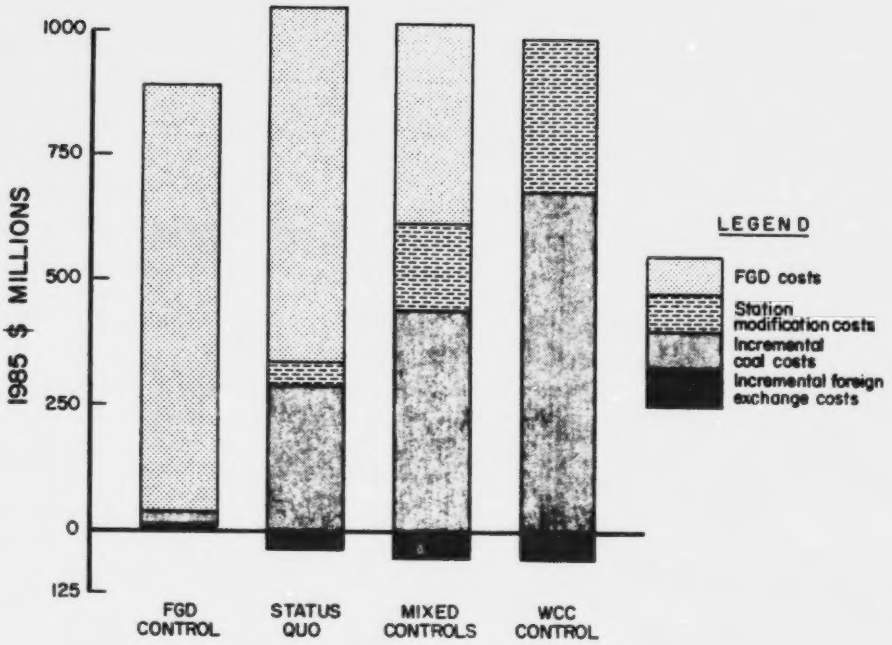


controlled exclusively with FGD; and about 16% more if emissions were controlled by expanded use of western Canadian coal. Additional annual costs for households are $39 and $79 under FGD and western Canadian control options, respectively. Additional annual expenditures for electricity by industry, agriculture, households, and commercial and institutional establishments is estimated to be $373 million and $741 million under the FGD and western Canadian Control options, respectively.

Additional annual expenditures for electricity by industry, agriculture, households, and commercial and institutional establishments are estimated to be $373 million and $741 million under the FGD and Western Canadian Control Scenarios, respectively.

Even with these increases over the no control situation, however, overall electricity prices are projected to decline (in constant dollar terms) between now and the year 2000 due to limited capital expenditures for new generating station construction. (Although no cost estimates have been made, it is anticipated that new capacity will have to be added in the late 1990s to maintain a sufficient system margin.)

Although the western Canadian control option does not appear to be attractive to Ontario Hydro, from the viewpoint of Canadian society, it may be cost-competitive. This result is attributed to a number of factors, an important one of which is the exclusion of taxes, profits, some financial charges, and other transfers from the price of Canadian coal. These items represent transfers between groups within Canada and are not generally considered costs to Canadian society as a whole. The (present value) social costs of emission control by FGD and western Canadian coal are $888 million and $950 million, respectively. The 7% difference in these estimates is within the margin of error for this study, indicating that, from the perspective of Canadian society, the two options are competitive at $87.75/t for western Canadian bituminous coal.



Sensitivity analysis suggests that the relative attractiveness of expanded use of western Canadian coal would be enhanced if:

- U.S. coal prices remained high (either through a higher exchange rate or higher mine prices than assumed by the Task Force);
- delivered prices for western bituminous coal fell; or
- the cost of labour was discounted or "shadow priced" to reflect possible high unemployment in the 1900s.

For example, if the Canadian/U.S. exchange stayed at its current (Feb. 1986) level, the western Canadian control option may, from a social perspective, be more advantageous than the FGD approach. If, however, expanded use of low-sulphur western Canadian coal resulted in boiler derating, incremental costs could rise well above the FGD/U.S. coal option.

Employment and Income Effects

Controlling acid gas emissions through expanded use of low-sulphur western Canadian coal is expected to generate about 205 000 person-years of Canadian employment (an average of almost 13 000 permanent jobs) between the years 1985 and 2000. The distribution of these employment effects is relatively evenly split between coal-producing provinces and Ontario. In British Columbia and Alberta about 86 000 person-years are projected, concentrated in the mining, rail transportation and service sectors; with an additional four thousand generated in Saskatchewan by transportation and service activity. About 85 000 person-years of employment are expected in Ontario, generated directly from station modification requirements and transportation and indirectly from manufacture of transportation and mining equipment and consumer goods. (About 30 000 person-years of employment are estimated to be generated in other provinces in Canada.)

EMPLOYMENT AND INCOME EFFECTS OF REDUCING ACID GAS EMISSIONS (1985 to 2000)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
EMPLOYMENT:				
(x 10^3 person-years)				
Total	104	147	175	205
Provincial Distribution				
B.C.	9	19	28	37
Alta.	10	25	35	49
Sask.	3	4	4	4
Ontario	71	82	85	85
Other Canada	11	17	23	30
INCOME (GDP):				
(1985 $ millions)				
Total	2421	3343	3833	4060
Provincial Distribution				
B.C.	301	550	680	745
Alta.	436	805	997	1107
Sask.	129	136	139	141
Ontario	1252	1486	1579	1553
Other Canada	303	366	438	514

Controlling acid gas emissions with FGD exclusively is expected to generate about 104 000 person-years of employment (an average of 6500 permanent jobs) between 1985 and 2000. This estimate suggests employment generation with FGD control will be about 50% of the employment generated under maximum expanded use of low-sulphur western coal. Differences between the two scenarios are concentrated in B.C. and Alberta where the rapid decline and potential phasing out of coal exports to Ontario under FGD control result in a significant decline in the employment base in the mining, transportation and service sectors. Considerable employment is created in Ontario by the manufacture, installation and operation of FGD systems. However, Ontario would experience more employment with expanded use of western Canadian coal (e.g., transportation and related equipment manufacturing). Controlling acid gas emissions with FGD exclusively, therefore, generates less employment in every province than by expanding the use of western Canadian coal.

Further analysis indicates that maximum expanded use of western Canadian coal would generate about 58 000 more person-years of Canadian employment than if current levels of western Canadian coal consumption were maintained. Emission control by FGD exclusively, however, would reduce this "status quo" employment base by about 43 000 person-years between the years 1985 and 2000.

The estimates of total Canadian employment - and the GDP figures presented in the following table must be interpreted as maximum values. They are gross estimates because they do not take into account substitution of existing employed workers, the degree to which new jobs are filled by the unemployed, and employment and income which would be generated by alternative investment opportunities. At a minimum, controlling acid gas emissions by expanded use of western Canadian coal will safeguard employment and income in coal mining and transportation which would flow to the United States under an FGD/U.S. coal option. A rough estimate of minimum employment effects associated with expanded use of western Canadian coal is 63 000 person-years (cumulative 1985 to 2000) over the FGD control scenario.

The pattern of Canadian income generation across coal use scenarios is similar to the employment profiles. The FGD control option would divert income opportunities to U.S. suppliers. The estimated present value of income generated by the FGD/U.S. coal option is $2.4 billion (over the 1985 to 2000 period). The comparable figure for expanded use of western Canadian coal, however, is $4.1 billion.

Environmental Implications

All four coal use scenarios examined by the Task Force meet the emission limits. Two intermediate scenarios maintain or expand consumption of low-sulphur coal between 1985 and 1990, resulting in a reduction in acid gas emissions well before the 215 kt/yr limit is reached in 1994. In these scenarios, SO_2 emission reductions total about 1860 kt over the period from 1985 to 2000, compared to the minimum removal of about 1635 kt required to meet the limit.

Increased use of western Canadian coal may result in negative environmental effects during coal mining and preparation, transport and combustion. Among the more significant effects are:

- temporary land area disruption (mining);
- solid and liquid waste generation (mining and preparation);
- fugitive dust emissions (mining, transportation and combustion);
- particulate emissions (preparation and combustion); and
- nuisance and safety (rail transportation).

There are, however, technologies, laws, and regulations to mitigate many of these environmental effects (e.g., land reclamation.) With these provisions, environmental effects are not expected to seriously impede expanded use of low-sulphur coal.

Emerging Technologies

The cost, employment, and GDP estimates, and environmental effects developed by the Task Force were based on available knowledge and technologies. During the next decade, before emission limits are reached, research and development may offer technological advances that could radically alter the relative attractiveness of options to reduce emissions.

Coal preparation and beneficiation technologies hold promise for enhancing calorific value and other characteristics of western Canadian coal. With associated changes in coal quality and reductions in delivered price, these technologies may improve the attractiveness of both western Canadian bituminous and subbituminous coals, and lignite.

Better quality bituminous coal would reduce combustion-related concerns, such as possible station derating. Improved quality of lignite and subbituminous coal combined with generating capacity additions capable of burning a wider variety of fuels (either conventional or fluidized bed combustion) in the late 1990s may make its expanded use more attractive.

Considerable effort is also being devoted to improving SO_2 control equipment, which could result in reductions in the cost of mechanical/chemical SO_2 removal and which may enhance the attractiveness of the U.S. coal option.

Summary

The findings of this Task Force suggest that, without control measures, the acid gas emission level of 215 kt/yr year (SO_2 and NO_x) will be exceeded in 1994. Expanded use of low-sulphur western Canadian coal may offer a cost-effective option for meeting the limit from the perspective of Canadian society as a whole but is considerably more expensive to Ontario Hydro than an FGD/U.S. coal option.

The competitiveness of expanded use of western Canadian coal is sensitive to both the delivered cost of the western coal and the cost of SO_2 control technologies. Further research into coal upgrading technologies may lower the price and enhance the quality of western Canadian coal to compare more favourably with U.S. coal.

Expanded use of western Canadian coal will generate substantial employment opportunities and sources of GDP compared to the FGD/U.S. coal option. These effects will occur in all provinces, including Ontario which benefits from demand for manufactured products and consumer goods from other provinces.

1 INTRODUCTION

The environmental and economic consequences of acid rain are major issues facing Canadian society today. Damage to aquatic systems caused by acid rain and sulphur dioxide (SO_2) emissions has been extensively documented, and the effects on forests and soils from chronic low-level exposure have received heightened attention recently. The effects of SO_2 emissions on human health are of concern and increased corrosion of buildings is known to be caused by sulphur deposition. Evidence of environmental damage and related economic consequences has stimulated both domestic and international discussions and negotiations on acid rain and SO_2 emissions.

Within Canada, resource and environment ministries devote considerable effort to identifying, analysing, and monitoring the effects of SO_2 emissions. Individual and cooperative efforts of federal and provincial resource and environment ministries have established a framework, strategy, and targets for abatement action in Eastern Canada for reduction of emission levels. The federal ministry has developed a detailed database and simulation model to assess the costs and effectiveness of flue gas desulphurization systems and other control alternatives.

In a further effort to identify opportunities for reducing acid gas emissions the "Task Force on Expanded Use in Ontario of Low-Sulphur Western Canadian Coal" was created in October, 1984 at the collective recommendation of federal and provincial Environment Ministers. The formal statement of purpose in the terms of reference of the Task Force is to "Assess the comparative costs and benefits of the expanded use of low-sulphur western coal in Ontario, including acid rain abatement strategies and economic aspects, taking note of the work already performed by the Alberta/Ontario Coal Task Force".

The Task Force focussed its investigations on the possibility of expanded use of low-sulphur western Canadian coal by Ontario Hydro to meet its demand for coal-generated electricity. Ontario Hydro is the largest single user of thermal coal in Ontario (85% to 95% of total thermal coal consumed in Ontario) and represents a significant source of acid gas emissions. Expanded use of western Canadian coal by non-utility companies was not considered because the Alberta/Ontario task force concluded there was limited potential for expanding their coal consumption beyond current levels (Alberta/Ontario, 1984).

The findings of the Task Force are documented in this report. Expanded use of low-sulphur western coal is examined to determine if it is an economically viable option for reducing SO_2 emissions from social and private perspectives. Data used in the analysis are preliminary, yielding order-of-magnitude estimates of costs and employment and income effects. The findings, therefore, are indicative; they are intended to contribute to a fuller understanding of the issue for future discussion and to provide input to the planning process. It is not intended that decisions on specific future coal use will stem from the information in this report alone. Definitive conclusions regarding the relative attractiveness of expanded use of western Canadian coal require more detailed analysis than possible in this overview.

1.1 Background

During the 1970 decade, emissions of sulphur dioxide and other pollutants were reduced in the United States and Canada to protect air quality and industrial working conditions. In Canada, various regulations, control orders, economic incentives, and environmental approvals were the instruments used to achieve reduction.

The need to further reduce sulphate loading on the natural environment became more apparent through the late 1970s as new evidence was gathered on the biophysical effects of acid rain. The evidence led to a second phase of attack on industrial air pollution (including the long range transport of air pollutants) which had international as well as domestic ramifications.

In the international forum, preliminary meetings and negotiations between Canada and the United States led to the signing of a "Memorandum of Intent of Transboundary Air Pollution", in August, 1980. The Memorandum stated the intention of both nations to vigorously enforce existing air pollution legislation and to work toward a bilateral agreement on air quality. Technical groups were established under the aegis of the Memorandum of Intent to study numerous issues in depth. Negotiations between the two countries were broken off in 1982 after U.S. representatives rejected a Canadian proposal to reduce sulphur dioxide emissions east of the Manitoba-Saskatchewan border by 50% with parallel action in the eastern United States.

In March, 1984, Canadian federal and provincial Environment Ministers decided to take unilateral action to reduce SO_2 emissions in Eastern Canada to about 2.3×10^6 t/yr by the year 1994 (a reduction of 50% from the 1980 base). At a subsequent meeting, Environment Ministers announced provincial allocations to achieve the 50% target.

As indicated in Table 1, Ontario's agreed share of total 1994 targets was 1030 kt/yr, an annual reduction of 1164 kt.

TABLE 1 PROVINCIAL TARGETS FOR SO_2 EMISSIONS (kt)

	1980 Base	1994 Targets	Reductions
Ontario	2194	1030	1164
Newfoundland	59	45	14
Nova Scotia	219	204	15
P.E.I.	6	5	1
New Brunswick	215	185	30
Quebec	1085	600	485
Manitoba	738	550	188
Total	4516	2619*	1897

* At the time of the agreement, approximately 319 kt of emission reductions had not been allocated.

A new Ontario control order legislated since the agreement has reduced Ontario's 1994 emission target to 885 kt. This new order requires Ontario Hydro to limit SO_2 emissions to 240 kt/yr by 1990 and 175 kt/yr by 1994 from a current (1986) control limit of 370 kt/yr. Corresponding new limits for combined SO_2 and NO_x emissions are 280 kt/yr by 1990 and 215 kt/yr by 1994 from a current control level of 430 kt/yr (Ontario Ministry of the Environment, 1985).

1.1.1 **Ontario Hydro's Abatement Options.** Within Ontario Hydro, the abatement options to meet new emission regulations are varied, arising not least from the fact that coal is a swing fuel used for peaking power and to take up the slack created by unanticipated problems in other parts of the system. Possible abatement options include:

- substitution of nuclear generation for coal-fired generation;
- coal washing;
- sorbent injection;
- flue gas desulphurization;
- expanded use of western coal;
- other (e.g., increased imports of electricity).

Nuclear generation. Ontario Hydro's short run policy is to continue its current program to reduce acid gas emissions by replacing coal-fired capacity with nuclear units. These units are due to come on stream between now and the early 1990's and coal will be used primarily as

TABLE 2 ONTARIO HYDRO ELECTRICITY DEMAND AND GENERATION (Ontario Hydro, 1984)

	1984		1986		1990	
	TWh	%	TWh	%	TWh	%
Generation:						
Hydroelectric	36	30	36	29	35	25
Purchases	7	6	5	4	2	2
Fossil	37	31	24	19	13	9
Nuclear	39	33	61	48	90	64
Total Electricity Demand	119	100	126	100	140	100

a swing fuel. Nuclear generation is projected to increase in the short term from 33% to 64% of total electricity demand (Table 2). By contrast, fossil-generated power is forecast to fall from 31% to 9% of total demand.

Coal preparation. All bituminous coal currently used by Ontario Hydro is prepared (by washing) to remove some of the inorganic sulphur compounds (primarily FeS_2) and non-combustible mineral matter (e.g., ash, clay, shale). This process raises calorific value and lowers sulphur content by about 20% to 30% (Ontario Hydro, 1980). Currently, the cost of preparation is approximately balanced by savings in transportation and boiler operations.

Improvements in the degree of coal preparation may be possible. For example, advanced physical coal cleaning processes may improve sulphur removal to about 25% to 35%. One of numerous promising technologies for bituminous coal is beneficiation by oil agglomeration. The Saskatchewan Power Corporation has pursued extensive research into lignite beneficiation. Emerging coal preparation technologies and their consequences for reducing acid gas emissions are discussed in more detail in Section 5.

Sorbent injection. Sulphur dioxide emissions can be reduced by replacing burners in existing boilers to permit the injection of sorbent (e.g., lime/limestone) directly into the boiler to absorb sulphur. The sorbent containing the captured sulphur is collected along with the fly ash in the station's electrostatic precipitators. Sorbent injection technologies are being actively pursued in an experimental/developmental project underway at the 300 MW Lakeview No. 4 twin boiler unit. Tests should be completed by the end of 1986, at a total cost of $4 200 000.

If the tests prove successful, sorbent injection could be installed at the larger Lambton generating units, which have similar boiler design principles to the Lakeview test boiler and were designed to burn coal which has the same characteristics (i.e., U.S. coal with a sulphur content of 1.6% to 2.5%). It is hoped that this technology will prove capable of removing at least 50% of SO_2 emissions.

Flue gas desulphurization. Flue gas desulphurization (FGD) refers to the removal of sulphur dioxide from the flue gas after combustion. The most common approach is wet scrubbing, although dry scrubbing can be used with some coal types. In wet scrubbing, sorbent slurry or solution is brought into contact with the flue gas, the sulphur dioxide in the flue gas reacts to form sulphite or sulphate salts which are carried away in the liquid for further processing and/or disposal.

Wet scrubbing is a proven technology capable of removing more than 90% of SO_2 from the flue gas at power plants burning medium to high sulphur coal. There are a number of wet scrubbing processes using different sorbents and producing different end products. The most likely one to be used in Canada is the limestone slurry gypsum process. The sorbent input is limestone ($CaCO_3$) and the output is gypsum ($CaSO_4 \cdot 2H_2O$).

Substantial capital, operation, and maintenance costs are associated with the use of FGD. FGD also consumes energy for operation, requiring the generation of additional electricity in the system.

Other acid gas control technologies. Current research may result in new acid gas control technologies. Promising areas of research are:

- sorbent injection (in-furnace and post-combustion);
- slagging combusters (Rockwell, TRW);
- irradiation methods (electron beam, UV light, etc.);
- combined particle/SO_2 removal (E-SO_x);
- NO_x control (staged combustion, SCR); and
- fluidized bed combustion (FBC).

The first five technologies are in-furnace or post-combustion processes applicable to conventional boilers while FBC is an entirely different boiler design concept. These technologies vary in their stage of development and may offer cost advantages over wet or dry scrubbing in the future.

Expanded use of western Canadian coal. Expanded use of low-sulphur coal is another option available to Ontario Hydro for reducing acid gas emissions. Western Canadian bituminous coal can be obtained with 0.2% to 0.5% sulphur compared to 2.2% average sulphur for the imported U.S. Appalachian coal.

Ontario Hydro has already switched some supplies to western Canadian coal. In the utility's "west" sub-system, the Thunder Bay and Atikokan plants have been modified or designed to burn lignite from Saskatchewan. The lignite contains about 0.5% sulphur, but because of its lower heat value, it is equivalent to about 1% sulphur in bituminous coal.

Ontario Hydro is also using about 2.3×10^6 t/yr of bituminous coal from Alberta and British Columbia. All of this coal is burned at the Nanticoke plant in the "east" sub-system. There are two other major coal burning plants in the east subsystem: Lakeview and Lambton. All three stations were originally designed to burn Pennsylvania and West Virginia coal, which have different combustion characteristics from Canadian coal, including: a higher heating value, lower moisture and ash content, and a higher volatile content. Differences in coal characteristics mean that use of western Canadian coal in ratios higher than 50/50 blend with U.S. coal will require combustion and emission control equipment modifications.

Blending and coal handling facilities may also be required. Boiler derating could also occur with higher than 50/50 blends.

Other abatement options. A number of other options to reduce acid gas emissions are open to Ontario Hydro. These include importing U.S. low-sulphur coal, increased electricity imports from Manitoba and/or Quebec, energy conservation, and electricity demand management. Both the importation of U.S. low-sulphur coal and increased electricity imports from Quebec, have potential to significantly reduce SO_2 emissions. However, there is no firm information at this time on what role either of these will play in Ontario Hydro's emission reduction plans.

1.1.2 Ontario Hydro Demand for Coal. Analysis of the potential for switching to western Canadian coal requires an estimation of Ontario Hydro's overall demand for coal over the next 15 years. Coal consumption by Ontario Hydro for the 1985 to 2000 year period will be highly dependent on a number of factors, including:

- electrical energy demand;
- hydroelectric and nuclear generating capability;
- electricity imports and exports; and
- load management.

Electrical energy demand. The National Energy Board (NEB) estimates that electricity demand in Ontario will grow at a rate of about 2.5% per year through the 1983 to 2000 year period (NEB, 1984). This growth rate is consistent with Ontario Hydro projections. Actual future demand growth, however, could vary substantially from this figure and it is important to realize that even small variances in the growth rate will strongly influence generating capacity requirements in the year 2000. Figure 1 shows that electricity demand in the year 2000 would be approximately 145 000 GWh, 183 000 GWh, 231 000 GWh at growth rates of 1%, 2.5%, and 4%, respectively. In terms of generating capability, almost 10 000 MW additional capability is required for the 4% growth rate (as opposed to 1%). This difference is equivalent to 3.5 nuclear stations the size of the 3400 MW Bruce B Station (at 80% capacity factor) or four fossil-fueled stations the size of the 4000 MW Nanticoke Station (at 65% capacity factor).

In terms of coal tonnage, the difference between the 1% and 4% growth rates, if made up entirely from coal-fired generation, is some 28×10^6 t/yr. Variations in the electrical energy demand, therefore, could drastically affect future coal requirements.

Hydroelectric and nuclear capacity. Current generating capacity in Ontario is split between three types: hydroelectric, nuclear, and coal-fired capacity. As illustrated in Figure 1, coal-fired electricity generation required in any given year will be the difference between total electricity demand and electricity available from hydroelectric, nuclear generation and purchases.

Hydroelectric generating capability in Ontario (approximately 40 000 GWh/yr) is not expected to change during the 1985 to 2000 year period, although there may be some small capacity additions in the 1990s (NEB, 1984). Hydroelectric generation capability is also dependent on variations in the hydrologic conditions. The effect of hydrologic variability is less pronounced in Ontario than in some other provinces because much of the hydroelectric capacity is on the St. Lawrence River where flow is regulated on a multi-year basis by the "International Joint Commission".

Some of Ontario hydroelectric capacity, however, does not have the benefit of Great Lakes moderation. In these cases, unusually dry or wet years could substantially alter hydroelectric production and, therefore, coal requirements to meet differential demand.

Nuclear generating capability in Ontario has grown rapidly in recent years, and will continue to increase until 1992 as new units come into service at the Bruce and Darlington generating stations (Table 2 and Figure 1). There are no known plans to further increase nuclear capacity between 1992 and the year 2000. With both hydroelectric and nuclear generation capability constant through the 1992 to 2000 year period, increases in electrical energy demand will be met by increasing generation at fossil-fuelled stations.

The availability of nuclear units is also of major importance. One 850 MW nuclear unit out of service for a year requires that two

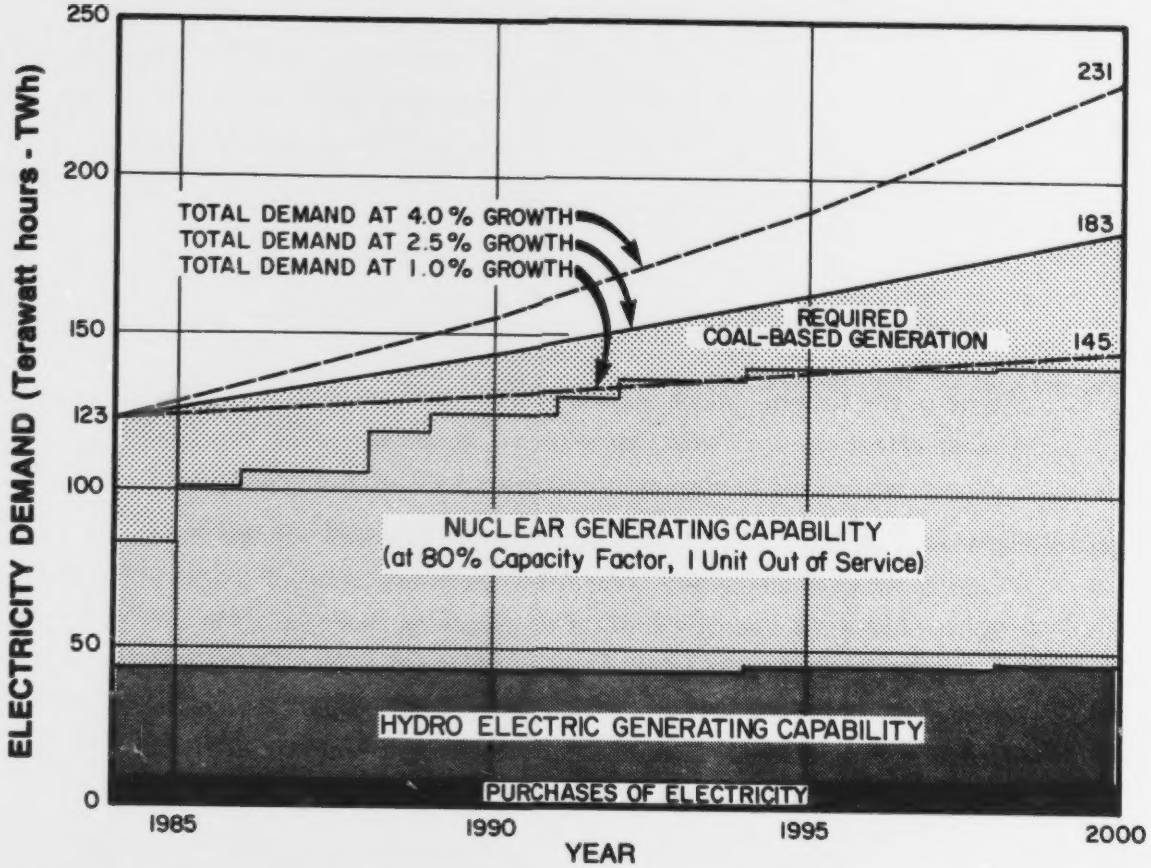


FIGURE 1 PROJECTED ELECTRICAL ENERGY DEMAND AND GENERATING CAPABILITY IN ONTARIO TO THE YEAR 2000

500 MW fossil-fuelled units be brought into service, consuming an additional two million tonnes of coal. If, for some reason, several of the large nuclear units expected to be in service by 1992 were out of service concurrently, coal consumption projections would increase substantially.

Electricity imports and exports. Electricity imports make up less than 5% of the Ontario demand, and are projected to drop to less than 1% by the year 2000 (NEB, 1984). Unless there are major changes in electricity purchases from Quebec and Manitoba, imports are not expected to substantially decrease projected coal consumption in Ontario. While recognizing that discussions are underway between Ontario Hydro and Hydro-Québec on potential electricity imports to Ontario in the late 1990s, the Task Force has assumed for calculation purposes, that electricity imports will remain constant throughout the 1985 to 2000 year period.

Agreement on major new transmission inter-ties with Hydro-Québec could substantially decrease, or theoretically, eliminate, the need for coal for electricity generation in southern Ontario some time in the future. Major purchases from Manitoba could have the same effect on the "west" subsystem. A move toward increased exports would tend to augment the demand for coal-fired electricity.

Load management. Load management could also decrease future coal consumption for electricity generation. Load management practices could reduce the size of the peaks by spreading energy demand over longer periods. Since fossil-fuelled stations are operated in a peaking mode in Ontario's system, load management could reduce the frequency that fossil units need to be brought into service and, consequently, overall coal consumption.

Other measures, such as energy price scales, increased energy conservation among users, and switching to alternative energy sources would also reduce long-term electricity demand and coal consumption.

A computer simulation model of Canadian electrical systems (CANSIM) was used to project coal use by Ontario between 1985 and the year 2000. The model has the flexibility to incorporate a range of assumptions concerning electricity demand: capacity factors of individual generating units at both fossil and nuclear stations; variability in coal quality; and other operating parameters and boundary conditions. Some of the more significant assumptions used in generating the coal consumption projections for the Task Force were:

- electricity demand growth of 2.5% from 1985 to the year 2000;
- constant hydroelectric generation of 35 TWh/yr from 1985 to 1994, with small additions in 1994 and 1998;

- all nuclear units operating at an 80% capacity factor, and only one unit out of service throughout the 1985 to 2000 year period;
- purchases of 8 TWh/yr from 1985 to the year 2000; and
- a maximum capacity factor of 65% at fossil-fueled stations.

Based on these assumptions, total coal demand by Ontario Hydro is expected to fall from 11 x 10^6 t/yr in 1985, to about 5 x 10^6 t/yr in 1992 (as nuclear units come on stream), and rise to about 14 x 10^6 t/yr by the year 2000. The projected resurgence in coal demand from about 1993 to the end of the century reflects increased use of thermal plants at higher capacity factors to handle growing demand not met by nuclear and hydroelectric generation.

1.2 Framework for Analysis

1.2.1 Coal Use and Emission Control Scenarios. Although it is recognized that other options for emission control are available to Ontario Hydro, only the costs and socioeconomic implications of FGD and the expanded use of western Canadian coal are assessed in this report. The FGD option was selected for comparison because it has been widely adopted in other countries, has proven application with the U.S. coal types currently being imported to Canada, and offers high removal efficiency capable of achieving the reduction targets. Also, detailed information on costs and operation is available for FGD.

To assess the relative merits of FGD control and expanded use of western Canadian coal, four scenarios of potential western Canadian coal use by Ontario Hydro (1985 to 2000) were developed by the Task Force. The scenarios were selected to provide a wide range of tonnage of western Canadian coal within the upper and lower bounds of forecast consumption, while meeting legislated emission control levels.

The four scenarios allow scale effects to be incorporated in the estimates of costs and benefits for the various stages of the fuel cycle: mining, transportation, combustion, and emissions control. None of the scenarios should be seen as target coal consumption levels for Ontario Hydro; there is no attempt to choose the optimal solution for the utility. Quantities, type, and sources of coal ultimately used will be based on numerous options available to Ontario Hydro to meet electricity demand and emission limits. The four scenarios were identified as a means to explore the possibilities for different U.S./western Canadian coal mixes.

Scenario One: **FGD Control Option (Current Ontario Hydro Forecast of Western Canadian Coal Use)**

This scenario defines the most likely pattern of western Canadian coal use given Ontario Hydro's current plans (Ontario Hydro, personal communication, April, 1985). It assumes that lignite consumption in the western system remains at the 1986 level of about 1 x 10^6 t/yr. It also assumes that, as total coal demand drops, contracted supplies from both the United States and Western Canada are negotiated downward. After 1992 (when demand for coal in Ontario is lowest and contracts with western Canadian suppliers expire), use of western bituminous coal is eliminated.

To maintain total acid gas emissions at the 280 kt/yr and 215 kt/yr limits, flue gas desulphurization systems must be installed starting in 1994. By the year 2000, FGD is required on eight units at Nanticoke, four units at Lambton and three units at Lakeview generating stations.

Scenario Two: **Status Quo Option (Current Level of Western Canadian Coal Use)**

In this scenario, both lignite and western Canadian bituminous coal consumption remain constant except for a few years in the trough of demand in the early 1990s (when less than the current 2.3 x 10^6 t/yr of western bituminous coal would be needed to maintain a 50/50 blend with U.S. coal at Nanticoke) and in the late 1990s (when more than 2.3 x 10^6 t/yr is required to maintain a 50/50 blend and meet increasing demand for coal-fired electricity).

Acid gas emissions are lower in the early years than under the FGD Control option because more low-sulphur Canadian coal is used. FGD is, however, still required by 1995 to keep total emissions below 215 kt/yr. FGD is added to all units at Lambton and Lakeview generating stations. Nanticoke is assumed to continue to operate on blend throughout the 1985 to 2000 year period, with three units switched back to U.S. coal in the year 2000 and FGD added to meet emission limits.

Scenario Three: **Mixed Controls Option (50/50 Split of U.S. and Western Canadian Bituminous Coal)**

This scenario was selected to give a mid-range consumption of western Canadian bituminous coal for economic comparisons. This mid-range consumption is such that expansion of the Thunder Bay terminal is not required before the year 2000 and combustion modifications would be needed at only one generating station. It also provides a fairly even mix in method of emission control between western coal and FGD, and does not cause a disruption in western coal supply.

The scenario assumes lignite consumption remains constant throughout the 1986 to 2000 year period and that approximately equal quantities of U.S. and Canadian bituminous coals make up the remainder of Ontario Hydro's fossil fuel demand throughout the period.

The Nanticoke station is assumed to operate on a 50/50 blend until 1994, when the lower Ontario emission limit comes into effect. From 1994 to 2000, Nanticoke units are gradually switched from blend to 100% Canadian coal at a rate that keeps U.S. and Canadian coal consumption in the system roughly the same. Lambton and Lakeview remain on U.S. coal throughout the period. FGD units are added first at Lambton starting in 1996 and then at Lakeview to provide the incremental emission reduction needed to meet the emission limit.

Because the scenario incorporates both abatement options (expanded use of western Canadian coal and FGD), it is referred to as the "Mixed Controls" option.

Another possible scenario would have been characterized by a 50/50 blend of U.S. and western Canadian coal (i.e., 50/50 blend burned at all stations). It was recognized, however, that Ontario Hydro would be able to purchase Appalachian coal of equivalent sulphur content to that of the blended coal (1.3% to 1.5%) at a lower cost. The Mixed Controls scenario, as previously described, was chosen because it combines control strategies (western Canadian coal and FGD) and draws coal supplies from both sources.

Scenario Four: Western Canadian Coal Control Option (Sufficient Western Canadian Coal to Keep Ontario Hydro Total Acid Gas Emissions Below 215 kt/yr after 1993)

Again, lignite coal use is held constant at the 1986 level through to the year 2000. Western Canadian bituminous coal consumption follows the same pattern as under the FGD Control scenario until acid gas emissions reach the 215 kt/yr limit in 1994. From that time, use of 0.3% sulphur western bituminous rises continuously (replacing U.S. supplies) to ensure total emissions remain at or below the limit.

Clearly, no FGD is required in this scenario. Station modifications are, however, required to enable low-sulphur coal to be burned. Station modifications include changes to electrostatic precipitators to ensure that particulate emissions remain below regulated limits. Station derating could be a problem, although it has not been explicitly incorporated into the base analysis as definite estimates of the extent of derating are not available. Derating is considered in the sensitivity analysis.

Summary of scenarios. Estimated coal consumption profiles for the four scenarios are illustrated in Figure 2. Coal tonnages for each scenario are presented in detail in Appendix A. Over the 1985 to 2000 year period, demand for western Canadian coal is greatest under the Western Canadian Coal (WCC) Control option. Under this scenario, Ontario Hydro requires 67.0×10^6 t of western Canadian bituminous coal over the 16 year period compared to 11.7×10^6 t under the FGD scenario; 37.4×10^6 t under the Status Quo scenario; and 54.7×10^6 t under the Mixed Controls scenario. Demand for western Canadian coal under the WCC Control scenario is heavily concentrated in the late 1990s, compared to more constant levels of demand under the Status Quo and Mixed Controls scenarios (Figure 2; Appendix A).

The coal volumes inherent in these scenarios may require contract purchases to be negotiated downward. As of May, 1985, Ontario Hydro held contracts with seven U.S. coal companies and three Canadian companies (Appendix B). Expiry dates on U.S. contracts range from 1986 to 1991, except for one mine which is owned by Ontario Hydro. Minimum annual purchases required under these contracts fall from 7.82×10^6 t in 1986 to 2.86×10^6 t in 1991. Both contracts for western Canadian bituminous coal (Luscar Ltd., Alta. and Byron Creek Colliers, B.C.) expire in 1992, until which time minimum annual purchases, as stipulated in the contracts, are 2.22×10^6 t. The lignite contract (Luscar Ltd., Sask.) runs until 1996, with minimum purchases of 975 kt/yr.

A fifth scenario was considered in which use of western Canadian coal is maintained at current levels until 1987, rising steadily thereafter to replace all U.S. coal by 1989. Acid gas emission levels remain substantially below all other scenarios, requiring no SO_2 control equipment over the planning period. This scenario was excluded from detailed analysis as it is not directly comparable to the other scenarios (which focus on meeting new acid gas emission regulations), nor is it likely to be considered a possible option from Ontario Hydro's perspective.

None of these scenarios assumes any introduction of Saskatchewan lignite or Alberta subbituminous coal into southern Ontario. While both of these fuels could be delivered to the southern Ontario power plants at a lower cost per unit of heat content ($\$/10^6$ kJ) their characteristics are such that they cannot be readily burned at these plants. Their use in southern Ontario is, therefore, assumed to be unlikely unless they are upgraded in quality or new generating capacity designed to burn them is built. Although they have been excluded from the analysis in this report for that reason, their potential in the time frame should not be overlooked as coal upgrading technologies evolve.

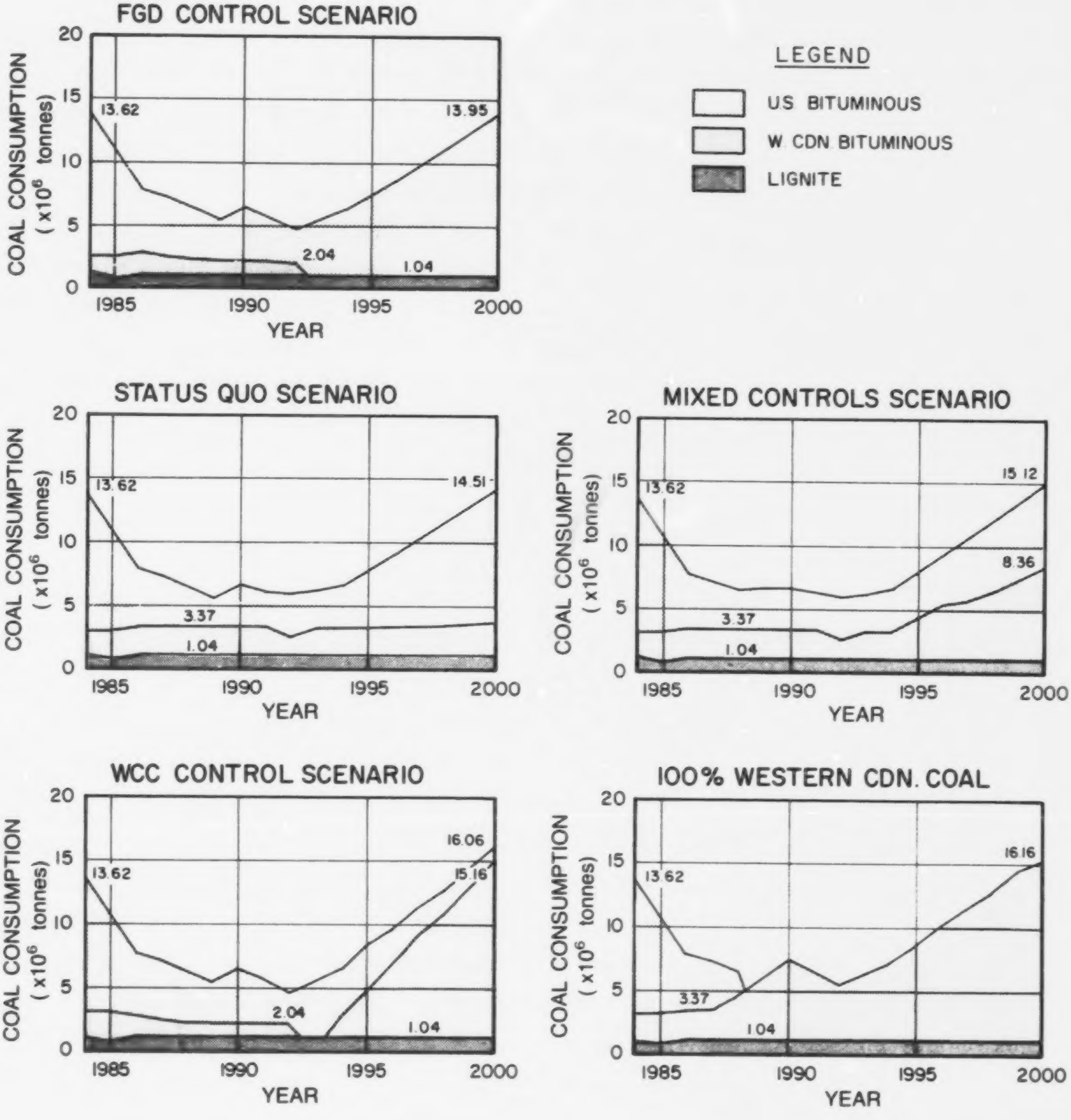


FIGURE 2 ONTARIO HYDRO COAL CONSUMPTION FOR SELECTED COAL USE SCENARIOS

Profiles of total acid gas emissions (SO_2 and NO_x) over the 1985 to 2000 year period for each of the four scenarios are illustrated in Figure 3. The uncontrolled case emissions are presented for comparison. The FGD and WCC Control options have essentially the same emission profiles; U.S. and western Canadian coal consumption is identical in the two scenarios until 1994 after which the 215 kt/yr SO_2 and NO_x limit is just maintained by alternative means. Total emissions over this period are 3.74×10^6 t in both scenarios.

Both the Status Quo and Mixed Controls scenarios have lower emissions in the early part of the planning period and reach the 215 kt/yr limit one year later (1995). Under the Mixed Controls scenario, gradual shifting of Nanticoke units from a 50/50 blend to 100% western Canadian coal delays the first FGD unit until 1996 and requires only nine units by the year 2000. Cumulative emissions for the entire 1985 to 2000 year period are about 3.50×10^6 t in both scenarios, or 6% lower than under the FGD or WCC Control scenarios.

In all four scenarios, SO_2 emissions remain below -- and in some cases, substantially below -- the 175 kt/yr limit. Sulphur dioxide emissions are forced below this limit to offset rising NO_x emissions (associated with increased coal use) and to ensure that combined totals of SO_2 and NO_x do not exceed the 215 kt/yr regulation.

1.2.2 Transportation Options. Three alternatives were considered for transporting western Canadian coal to Ontario:

- rail and laker across Canada;
- rail and vessel via the Panama Canal; and
- slurry pipeline across Canada.

Under the **rail and laker** alternative, Canadian coal and lignite are moved by dedicated trains from the mine sites to the Thunder Bay terminal. Currently, dedicated CP coal trains use "train sets" of 108 cars with four locomotives; CN trains use 98 cars with four locomotives. The average turn-around time is five days and in an operational year each train set carries between 550 and 650 kt of coal. Five trains per week currently move between the mines and Thunder Bay.

At Thunder Bay, lignite is moved by conveyor belt to the thermal plant. Bituminous coal is stored and transferred to self-unloading lakers for shipment through the Great Lakes System to generating stations in Ontario Hydro's east subsystem. The rail and laker alternative is examined for all scenarios.

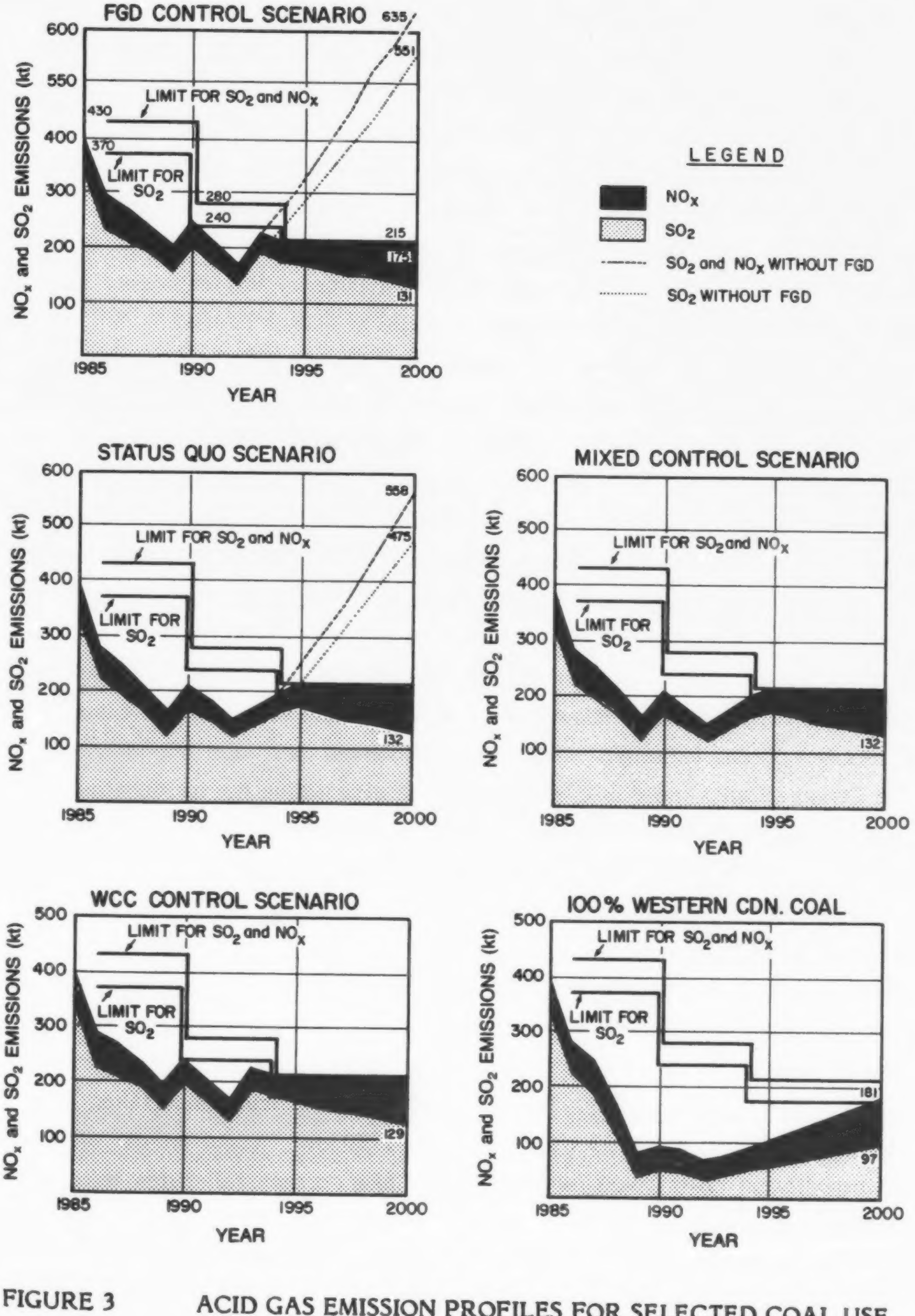


FIGURE 3 ACID GAS EMISSION PROFILES FOR SELECTED COAL USE SCENARIOS

The Panama Canal route involves transporting coal across British Columbia by rail to the terminal at Roberts Bank. If this route were used, coal would be shipped from Roberts Bank down the west coast of North America, through the Panama Canal, and up the east coast to a transfer point on the St. Lawrence River. There, it would be transferred to lakers and shipped through the St. Lawrence Seaway to Ontario Hydro generating stations on the Great Lakes. Lignite coal would be transported over land.

At present, costs of transporting coal via the Panama Canal are comparable to the rail and laker option as current idle capacity in the industry has depressed world shipping rates. As this capacity is absorbed, however, rates are likely to rise.

The viability of the Panama Canal route also depends on Canadian shipping regulations. Current Canadian law states that a Canadian ship must be used for intercoastal trading. A waiver may be secured if a suitable Canadian ship is not available. (Suitability is defined in terms of both price and type of ship.) Because the waiver must be obtained for each movement, long-term contracts with non-Canadian shipping companies cannot be negotiated. However, shippers are not likely to forfeit possible cost advantages by signing long-term contracts with Canadian companies.

By rough calculation, the Panama Canal route for interior coal would cost about $88/t, made up of $35/t, $20/t, $5/t and $28/t for mine, overland rail, terminal, and vessel charges respectively. Because this route is likely to be the same or more expensive than the rail and laker option, it has not been analysed in detail.

The Panama Canal route is a very attractive alternative for transporting low sulphur coal from Vancouver Island's proposed Quinsam mine to Ontario. The mine, which could produce one million tonnes annually, is situated at tidewater which eliminates land transportation costs associated with inland coal and reduces overall transportation costs by about 40%.

Slurry pipelines are still being developed. At present, a coal/water slurry pipeline operates in Nevada. The coal is ground to a 0.25 cm diameter particle size and mixed in a 50/50 blend with water. The pipeline is 437 km long, has four pumping stations, and moves coal at 5×10^6 t/yr. Engineering analysis is being undertaken for a coal/water slurry pipeline to move 23×10^6 t/yr over 1760 km. Based on the Nevada experience, transportation costs could be 40% lower than current rail rates once the pipeline is in place (Bechtel Corp., 1985).

In assessing the coal/water pipeline alternative in the western Canadian coal setting, a number of factors must be taken into consideration:

1) cross-Prairie pipeline capacity is fully dedicated and this situation is likely to prevail for some time; a right-of-way must be obtained, therefore, and a pipeline of suitable size must be constructed;
2) a sufficient supply of water at the mine site must be assured;
3) adequate receiving and storage facilities must be built in Ontario, adding to the high cost of the pipeline investment; and
4) a minimum of 8×10^6 t/yr of coal on a regular basis must be guaranteed.

Although the Nevada experience is encouraging, technical problems of operating a slurry pipeline of very long distances (for example, from Alberta/B.C. mines to Thunder Bay) have not yet been fully resolved.

The burden of capital expenditures required for a dedicated coal slurry pipeline could be reduced by sharing the facility with oil movements. Technical uncertainties and problems of sharing have been raised with this alternative, but these perhaps could be overcome.

Further consideration of pipeline transportation of coal must take into account the consequences of removing this lucrative trade from Canadian railway companies, resulting in changes in the cost of rail transport and, therefore, competitiveness of other Canadian products. In this context, it should be recognized that coal volumes will likely decline in the mid-years but potentially occupy a greater share of the transportation in the late 1990s.

Because of the uncertainties surrounding the slurry pipeline alternative and lack of reliable cost data, it has not been analysed in detail in this report. Nevertheless, it should not be discarded entirely from future consideration.

Summary of transportation options. Two of the three transportation alternatives have been excluded from detailed analysis: rail and vessel via Panama Canal; and slurry pipeline across Canada.

The Panama Canal alternative has been excluded because it represents a comparable or higher cost option than the overland route. The slurry pipeline alternative has been excluded because of technical uncertainties and lack of reliable technical and cost data. In all scenarios, therefore, western Canadian coal is assumed to be transported via rail and laker across Canada.

1.2.3 Other Assumptions. The analyses of costs and effects of expanded use of western Canadian coal are based on a number of additional assumptions:

1) coal, sulphur, and heat contents are the same as those specified in the Alberta/Ontario Task Force report; base year (1985) (coal prices are those obtained from Ontario Hydro);

	Heat Content (kJ/kg)	Sulphur (%)	1985 Price ($/t)
U.S. Bituminous	30 460	2.2	69.45
Cdn. Bituminous	25 340	0.3	90.75
Cdn. Lignite	16 040	0.5	46.35

2) raw coal will be prepared for shipment using existing coal preparation technologies; no additional upgrading will be included, although a discussion of the implications of emerging preparation technologies are adressed in Section 5;
3) low NO_x burners are installed on all Ontario Hydro fossil-fuelled generating units by the year 2000 in all scenarios;
4) the planning period is 16 years, from 1985 to 2000;
5) all costs and prices are given in 1985 Canadian dollars; and
6) the discount rate for Ontario Hydro is 6.6%; 7.1% for mining, terminal and lake transportation; and the social discount rate is 10% (all discount rates exclude factors for inflation).

1.2.4 Structure of Report. To ensure an adequate assessment of the four abatement options, the Task Force has adopted a broad evaluation approach, covering a number of cost and benefit indicators. In Section 2, the direct costs of reducing acid gas emissions under each scenario are presented and analysed. Costs are compared across scenarios from both the perspective of the utility and the perspective of society as a whole. The differences between private costs and social costs are explained and costs are described in present value terms.

Section 3 focuses on the effects on employment, income, coal industry and community stability. Estimates of the number of jobs, person-years, labour income, and gross domestic product are developed and compared.

Section 4 addresses environmental implications of each scenario during each stage of the coal use cycle (mining, preparation, transportation, and combustion).

As previously discussed, the acid gas emission limits do not necessitate expanded use of western Canadian coal and/or FGD until the mid 1990s. During the intervening years, numerous technological developments may alter the findings presented in this report. Section 5 is devoted to a discussion of possible developments and consequences for the attractiveness of western Canadian coal. Emerging coal preparation and SO_2 control technologies and slurry pipelines are covered.

2 COSTS OF REDUCING ACID GAS EMISSIONS

The purpose of this section is to compare estimates of the costs of reducing acid gas emissions under each of the four coal use scenarios (i.e., FGD Control, Status Quo, Mixed Controls, and Western Canadian Coal Control). Costs of reducing acid gas emissions are calculated as the incremental costs of generating coal-fired electricity above a "no control" case. Incremental costs are incurred for delivered coal, station modifications, emission control equipment or combinations thereof.

Because cost data form the foundation of all subsequent analyses, they are presented in detail by component in the coal use cycle. A summary of delivered coal prices (combining mine and transportation prices) is also presented. Within each section, estimates for capital and operating costs are presented for each scenario.

Primary data were developed by the following groups:

- Environment Canada (FGD and station operating costs);
- Ontario Ministry of the Environment (station modification and FGD capital costs, as prepared by Monenco Ltd.);
- Transport Canada (transportation costs); and
- Energy, Mines and Resources (mine development costs and supply price of coal).

A complete set of data and sources is found in Appendix A.

The cost figures presented are order-of-magnitude. Direct input from Ontario Hydro was not available to the Task Force and estimates take only rough account of the utility's operating conditions and philosophy.

The costs of reducing acid gas emissions under different options are compared from both Ontario Hydro's perspective (private costs) and the perspective of Canadian society as a whole (social costs). The comparison of costs to Ontario Hydro among the scenarios is presented and the implications of these costs to Ontario electricity customers are discussed.

To compare the costs of reducing acid gas emissions from the perspective of Canadian society, private costs are adjusted to reflect social costs. Social costs exclude taxes, subsidies, and other items which are not true costs to Canadian society as a whole, and incorporate costs not captured in a private analysis (such as foreign exchange premiums).

The cost estimates are based on a number of assumptions. Tests were conducted to determine the sensitivity of private and social cost estimates to these assumptions. Results are presented for the private and social cost analyses.

2.1 Mining Costs

The cost of coal at the mine site is based on the mine price per tonne and volume mined and prepared. Mine prices for U.S. coal, lignite, and western Canadian bituminous coal are presented in the following subsections. United States coal and lignite prices, which do not vary in the scenarios, are discussed in the next subsection. Supply, development costs, and prices for western Canadian bituminous coal are discussed in subsequent subsections.

2.1.1 Mine Prices for U.S. Coal and Western Canadian Lignite. The price of U.S. coal at the mine site is currently about U.S. \$39.60/t (Cdn. \$54.45/t). Future U.S. coal prices at the mine are assumed to follow projections for heavy fuel oil prices, which suggest that (1985 dollar) prices will fall in 1986 and 1987, remain constant until 1991, and rise at 1% per year thereafter (Canadian Energy Research Institute, personal communication, May, 1985).

Within the volumes discussed in this report, U.S. mine prices do not vary with quantity. The U.S. coal price profile, therefore, is the same for all scenarios.

The mine cost of U.S. coal to Canadian buyers will also depend on the U.S./Canadian exchange rate. The February 1986 rate was about (U.S.) \$1 = \$1.40 (Cdn) (Bank of Canada, personal communication). The likelihood of correctly forecasting foreign exchange rates, particularly in today's environment, is extremely low. For this analysis, the exchange rate is assumed to fall from the present rate to a 20-year average of about \$1.15 (Statistics Canada) by 1990 and remain constant thereafter. Sensitivity tests are undertaken for lower exchange rates.

As indicated in Table 3, the combination of declining heavy oil prices and a drop in the foreign exchange rate will cause a significant fall in U.S. coal prices (in Canadian dollars) between 1985 and 1990. Notwithstanding an annual 1% increase after 1990, this drop is sufficient to keep mine prices below 1985 levels through the year 2000. Specifically, U.S. coal prices at the mine will fall from \$54.45/t (Cdn.) in 1985 to \$46.75/t (Cdn.) in the year 2000.

The current price of western Canadian lignite at the mine site is about \$14.60/t. This price is assumed to remain constant (in real terms) throughout the 16-year planning period and through all scenarios. The price profile for lignite is also presented in Table 3.

TABLE 3 ESTIMATED MINE PRICES OF U.S. COAL AND WESTERN CANADIAN LIGNITE (1985)

Year	U.S. Coal	Lignite
1985	54.45	14.60
1986	50.65	14.60
1987	47.10	14.60
1988	45.45	14.60
1989	43.80	14.60
1990	42.30	14.60
1991	42.75	14.60
1992	43.15	14.60
1993	43.60	14.60
1994	44.05	14.60
1995	44.45	14.60
1996	44.90	14.60
1997	45.35	14.60
1998	45.80	14.60
1999	46.25	14.60
2000	46.75	14.60

Note:
- prices are valid for all scenarios
- prices are given in Canadian dollars per tonne

2.1.2 **Supply of Western Canadian Bituminous Coal.** Under the Western Canadian Coal Control scenario, 14.12 x 10^6 t/yr of western bituminous coal will be needed by the year 2000 (11.81 x 10^6 t/yr more than is currently delivered to Ontario Hydro). A review of bituminous thermal coal supply potential in Western Canada indicates there is no shortage of coal resources available to meet this demand nor companies willing to develop the supplies.

Even if offshore thermal coal sales rise from the current level of 5 x 10^6 t/yr to 20 x 10^6 t/yr by the year 2000, coal producers estimate there would be sufficient additional supply capability to meet Ontario Hydro demand up to 30 x 10^6 t/yr.

For this analysis, incremental bituminous thermal coal supplies are assumed to come from open-pit surface mines in central Alberta and southeast British Columbia. The

2.3 x 10^6 t/yr currently supplied can likely be expanded to 4.0 x 10^6 t/yr from existing coal mines without additional expenditure because of existing under-utilized mine capacity. A further 2.0 x 10^6 t/yr is available from minor expansions of existing mines. Minor expansions entail: additions to equipment to assist the removal of overburden and coal; modifications to preparation plants; and supplements to mine support facilities. The remainder of the coal supply is assumed to come from new sources either through major expansions of existing mines (up to 3.0 x 10^6 t/yr additional) or development of new mine capacity (up to 6.0 x 10^6 t/yr).

Table 4 illustrates sources of coal supply up to 15 x 10^6 t/yr. As indicated, incremental bituminous supply is assumed to develop in British Columbia and Alberta in the same ratio as existing supply (i.e., 67%, Alberta and 33%, British Columbia).

TABLE 4 BITUMINOUS SUPPLY DEVELOPMENT BY REGION (x 10^6 t/yr)

	Alberta	British Columbia	Total
Under-utilized supply	1.1	0.6	1.7
Minor mine expansion(s)	1.3	0.7	2.0
Major mine expansion(s)	2.0	1.0	3.0
New mine capacity	4.0	2.0	6.0
Incremental Supply	**8.4**	**4.3**	**12.7**
Existing Supply	1.6	0.7	2.3
Total Supply	**10.0**	**5.0**	**15.0**

For the purposes of this analysis, British Columbia's tidewater coal is not included as a supply source for Ontario Hydro. The proposed Quinsam coal mine on Vancouver Island, for example, has reserves of about 38 x 10^6 t of high volatile bituminous coal with a heat content of 28 000 kJ/kg and less than 1% sulphur (Canadian Mining Journal, 1984). The Quinsam mine could produce about one million tonnes annually and its close proximity to tidewater would substantially reduce transportation costs. Western tidewater coal, therefore, offers an opportunity to deliver a limited supply of good quality coal at a more competitive price than western Canadian coal from Alberta and interior British Columbia. The delivered price of Quinsam coal is roughly estimated at about \$83/t (\$50/t, \$5/t and \$28/t for mine, terminal and vessel charges, respectively).

2.1.3 Prices of Western Canadian Bituminous Coal. A base price for western Canadian bituminous coal at the mine site was assumed to be $38/t in 1985, falling to $35/t in 1986. These prices are considered representative of average prices paid for all western Canadian bituminous coals (FOB rail car).

The average mine price was developed from a review of 45 individual thermal coal selling prices of existing mines from 1981 to 1983. The summary of these prices is:

Year	Volume (x 10^6 t)	Average Price FOB Mine	Average Price Range FOB Mine
1981	1.83	$34.80	$28.65 to $47.35
1982	2.97	$38.35	$33.25 to $49.10
1983	2.29	$32.50	$25.50 to $39.45

Note: FOB denotes prices are "free-on-board", a term applied to the valuation of goods up to the point of embarkation and excludes freight and insurance costs.

Actual prices paid by Ontario Hydro will depend on mine developments and capital investments required to supply incremental coal volumes. Mine costs vary with the extent of development required. Capital expenditure requirements are based on the following assumptions:

- conventional truck and shovel and/or drag line operations are used;
- raw coal is prepared for shipment using existing coal preparation technology only (enhanced preparation and beneficiation of coals using new technology is discussed in Section 5.1, but is not considered in the base cost analysis); and
- major infrastructure requirements such as towns, rail access, road access, power source, gas, and water are already available to the mine site.

Average capital requirements for various mine expansions are presented in Table 5. These costs vary above and below the averages, depending on conditions of specific mine locations. For example, $50 for additional tonne of annual capacity for major expansions assumes new equipment is purchased. Where used equipment can be acquired or transferred from other sites, costs are lower.

Repayment of capital expenditures raises the price of coal from new supply sources. Capital recovery factors are calculated from average capital requirements per tonne, assuming that the (real) interest rate is 7.1% and that new coal supplies are contracted for a minimum of 10 years.* For example, average capital requirements for major mine expansions ($50 per additional tonne of annual capacity) adds $7.50/t to the base price of $35/t.

The price of coal from major mine expansions, therefore, is estimated at $42.50/t. Coal prices for the various supply sources are also presented in Table 5.

TABLE 5 ESTIMATED AVERAGE CAPITAL REQUIREMENTS AND COAL PRICES FOR WESTERN CANADIAN BITUMINOUS COAL (1985 dollars)

	Average Capital Investment Required ($/t additional annual capacity)	Average Price FOB Mine ($/t)
Existing Supply Sources (No Expansion)	0.0	35.00
Minor Mine Expansion	10.0	36.50
Major Mine Expansion	50.0	42.50
New Mine Capacity	100.0	50.00

Average mine prices used in this analysis are calculated as a blended price from various supply sources. The mix of supply sources and therefore, average mine prices differ among coal use scenarios. A description of mine development requirements and mine prices for each scenario follows.

FGD Control Scenario. Under the FGD scenario, consumption of western Canadian bituminous coal falls below current levels. Capital requirements, therefore, are not necessary and the mine price of coal is assumed to be constant at $35/t (after 1985).

Status Quo Scenario. Under the Status Quo scenario, consumption of western Canadian coal does not rise above current levels; therefore, no investment in new mine capacity is required and the mine price of western Canadian bituminous coal remains constant at $35/t (after 1985).

Mixed Controls Scenario. Under the Mixed Controls scenario, all current excess capacity (1.7×10^6 t/yr) is absorbed and 3.3×10^6 t/yr is added through minor (2×10^6 t) and major

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* Interest rates for mining, vessel and terminal sectors are derived from current corporate bond yields, adjusted for inflation using Statistics Canada CPI data (Appendix A).

(1.3 x 10^6 t) mine expansions. Total capital costs based on per tonne capital requirements presented in Table 5 are $2.5 million in 1995 rising continuously to $32.3 million in 1999. Total discounted capital costs amount to about $45 million over the 16-year period. (The discounted estimate is considerably smaller than the undiscounted total of $99 million because expenditures occur far in the future).

Capital repayment for these expansions steadily raises the price of western Canadian bituminous coal from $35/t in 1995 to about $36.70/t by the year 2000 (Table 6).

TABLE 6 ESTIMATED MINE PRICES OF WESTERN CANADIAN BITUMINOUS COAL (1985 dollars)

		Scenario ($/tonne)		
Year	FGD Control	Status Quo	Mixed Controls*	WCC Control**
1985	38.00	38.00	38.00	38.00
1986	35.00	35.00	35.00	35.00
1987	35.00	35.00	35.00	35.00
1988	35.00	35.00	35.00	35.00
1989	35.00	35.00	35.00	35.00
1990	35.00	35.00	35.00	35.00
1991	35.00	35.00	35.00	35.00
1992	35.00	35.00	35.00	35.00
1993	35.00	35.00	35.00	35.00
1994	35.00	35.00	35.00	35.00
1995	35.00	35.00	35.00	35.00
1996	35.00	35.00	35.20	35.50
1997	35.00	35.00	35.30	37.20
1998	35.00	35.00	35.40	38.50
1999	35.00	35.00	35.80	40.70
2000	35.00	35.00	36.70	42.20

* includes capital repayment for minor and major mine expansions

** includes capital repayment for minor and major mine expansions and new mine equipment

Western Canadian Coal Control Scenario. Under this scenario, coal production capacity must be expanded by almost 12×10^6 t/yr by the year 2000. The source, sequence, and cost of required mine developments in addition to utilization of existing capacity (1.7×10^6 t/yr) is assumed to be:

Minor mine expansion	2.0×10^6 t/yr	1994 to 1995	$ 20 million
Major mine expansion	3.0×10^6 t/yr	1995 to 1997	$150 million
New mine	5.1×10^6 t/yr	1996 to 1999	$509 million

Total capital expenditure in present value terms are estimated at $310 million.

The effect of these capital expenditures on mine prices is indicated in Table 6. Mine prices remain constant at $35/t until 1995, after which the more costly coal from new supplies raises the overall average price. By the year 2000, the average price of western Canadian bituminous coal is expected to reach about $42.20/t.

2.1.4 Summary of Mine Prices.

Capital expenditures are highest under the WCC Control scenario, reflecting extensive mine developments to meet demand in the late 1990s. Total (discounted) costs are $310 million for minor, major, and new mine developments, compared with $45 million under the Mixed Controls scenario. Under the FGD Control and Status Quo scenarios, coal production remains at or below current levels; therefore, no capital costs are incurred.

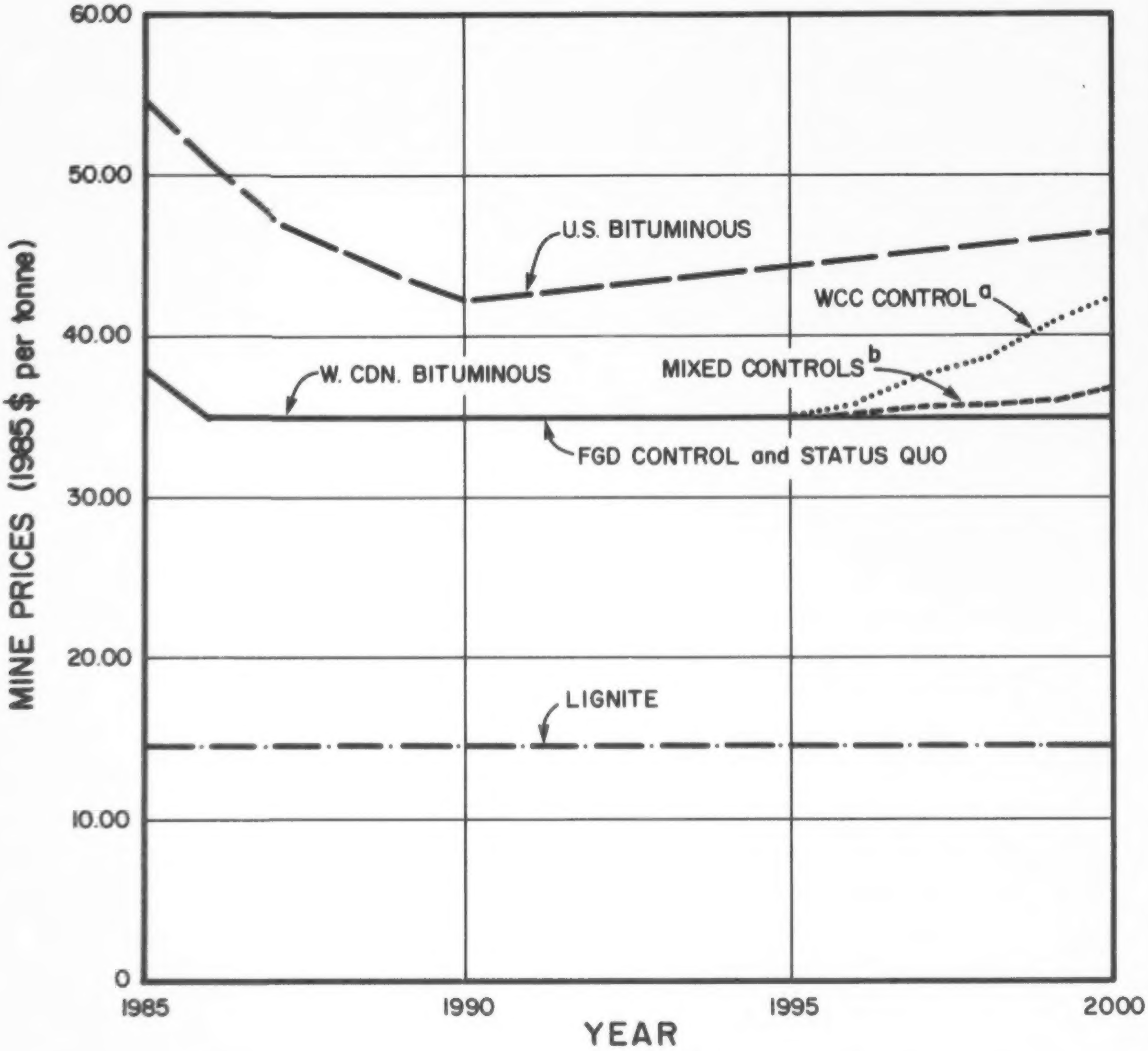
Mine development costs are reflected in the price profiles for western Canadian bituminous coal. As Figure 4 illustrates, bituminous coal prices rise most significantly under the WCC Control scenario (to $42.20/t by the year 2000). Prices also rise under the Mixed Controls scenario (to $36.70/t) but remain constant at the 1986 level ($35.00/t) under the FGD Control and Status Quo scenarios.

Mine prices for western Canadian lignite do not vary across scenarios and remain at the 1985 price of $14.60/t throughout the 16-year planning period.

United States coal prices do not vary among scenarios, but are affected by the forecast for heavy oil prices and the decline in the exchange rate. United States prices shown in Figure 4 are based on a 20-year average exchange rate and an assumption of declining heavy fuel oil prices between 1985 and 1988. Sensitivity tests are, however, performed for both these factors later in the analysis.

2.2 Transportation Costs

The second component of the delivered price of coal is transportation. At present, the cost of moving U.S. coal to Ontario Hydro sites is about $15/t. The cost of moving western Canadian bituminous coal to the same sites is $52.75/t.



[a] Includes capital repayment for minor and major mine expansions and new mine development
[b] Includes capital repayment for minor and major mine expansions
Note: All prices in Canadian dollars

FIGURE 4 SUMMARY OF ESTIMATED MINE PRICES 1985 to 2000 (1985 prices)

Transportation prices for each coal type and each scenario are outlined in the next subsection, including an explanation of capital costs where expansion of present facilities, railroad rolling stock, or laker fleets are required. Coal transportation costs are presented for rail/laker across Canada only.

2.2.1 Transportation Prices for U.S. Coal and Western Canadian Lignite. The current average price of transporting U.S. coal to Ontario Hydro sites is $15/t. This price is not sensitive to changes in volumes shipped and, therefore, is assumed to be the same for all scenarios. As illustrated in Table 7, however, the price will fall over time (from $15/t in 1985 to about $12.60/t by 1990) as the exchange rate drops to its 20-year average.

The transportation price of lignite coal has two components: rail costs and terminal costs. Rail charges are currently $26/t and terminal charges are $5.75/t. Both components are assumed to remain constant over time, giving a transportation price of $31.75/t for all scenarios (Table 7).

TABLE 7 ESTIMATED TRANSPORTATION PRICES FOR U.S. COAL AND WESTERN CANADIAN LIGNITE

		Lignite		
Year	U.S. Coal*	Rail	Terminal	Total
1985	15.00	26.00	5.75	31.75
1986	14.50	26.00	5.75	31.75
1987	14.00	26.00	5.75	31.75
1988	13.55	26.00	5.75	31.75
1989	13.05	26.00	5.75	31.75
1990	12.60	26.00	5.75	31.75
1991	12.60	26.00	5.75	31.75
1992	12.60	26.00	5.75	31.75
1993	12.60	26.00	5.75	31.75
1994	12.60	26.00	5.75	31.75
1995	12.60	26.00	5.75	31.75
1996	12.60	26.00	5.75	31.75
1997	12.60	26.00	5.75	31.75
1998	12.60	26.00	5.75	31.75
1999	12.60	26.00	5.75	31.75
2000	12.60	26.00	5.75	31.75

Note: prices are valid for all scenarios; prices are given in Canadian dollars per tonne
* price reduction is attributable to dropping exchange rate

2.2.2 Transportation Prices for Western Canadian Bituminous Coal. The transportation price for western Canadian bituminous coal has three components: rail tariffs, terminal charges, and vessel (water transport) expenses. The rates for all three components vary substantially among the scenarios, influenced by capital expenditures on new equipment.

No additions to rail line capacity are required in any of the scenarios since there are relatively few bottlenecks for coal shipments up to 20×10^6 t/yr. Double tracking and other improvements are expected to proceed steadily throughout the study period, and there is no evidence of serious capacity constraints along the eastbound rail system.

FGD Control Scenario. Because coal shipments never rise above current levels and existing transportation is adequate, no capital investments are required under this scenario. It is assumed no penalty is incurred for lower shipment volumes. Prices for terminal and vessel components, therefore, are expected to remain at the assumed 1985 rates of $5.75/t and $7.00/t, respectively. Rail tariffs are assumed to remain at the current rate of $40.00/t until capital repayment on existing rail cars is complete (1987), after which prices fall to $36.00/t. Total transportation prices, therefore, are $52.75/t to 1987, and $48.75/t from 1988 to 2000 (Table 8).

TABLE 8 ESTIMATED TRANSPORTATION PRICES FOR WESTERN CANADIAN BITUMINOUS COAL: FGD CONTROL AND STATUS QUO SCENARIOS (1985 $/t)

	Rail	Terminal	Vessel	Total
1985	40.00	5.75	7.00	52.75
1986	40.00	5.75	7.00	52.75
1987	40.00	5.75	7.00	52.75
1988	36.00	5.75	7.00	48.75
1989	36.00	5.75	7.00	48.75
1990	36.00	5.75	7.00	48.75
1991	36.00	5.75	7.00	48.75
1992	36.00	5.75	7.00	48.75
1993	36.00	5.75	7.00	48.75
1994	36.00	5.75	7.00	48.75
1995	36.00	5.75	7.00	48.75
1996	36.00	5.75	7.00	48.75
1997	36.00	5.75	7.00	48.75
1998	36.00	5.75	7.00	48.75
1999	36.00	5.75	7.00	48.75
2000	36.00	5.75	7.00	48.75

Status Quo Scenario. No capital investment in new transportation equipment is required under this scenario; therefore, all prices are the same as those for the FGD Control scenario.

Mixed Controls Scenario. Under this scenario, shipments of western Candian bituminous coal remain relatively constant at 2.3×10^6 t/yr until 1991, rising to a maximum of 7.32×10^6 t/yr by the year 2000. Increased throughput between 1995 and the year 2000 requires nine additional train sets of 600 kt/yr capacity per set. The first two sets are purchased in 1994, for initial use in 1995 with subsequent purchases spread out over the 1995 to 2000 year period. Each train set costs $14.5 million.

Incorporating a repayment factor for these capital costs* and averaging annual prices over five-year intervals, rail prices are estimated to fall from $40.00/t in 1985 to $37.00/t between 1991 and 1995, as existing train sets are repaid. After 1995, however, prices rise to $38.50, reflecting repayment requirements on new train sets.

No expansion to the Thunder Bay terminal is needed under the Mixed Controls scenario. Assumed handling charges at the terminal are $5.75/t through 1990, decreasing with growth in throughput to average $4.65/t in the 1996 to 2000 year period (as repayments on existing capital are spread out over larger volumes).

It is assumed that incremental coal volumes can be handled with the existing fleet of lake vessels and no new investments are required. Vessel charges remain constant at $7/t from 1985 through 2000.

Capital expenditures and prices of transporting western Canadian coal under the Mixed Controls scenario are presented in Table 9. On a discounted basis, capital expenditures amount to $63.3 million, consisting entirely of train set costs.

Transportation prices under the Mixed Controls scenario are also shown by component in Table 9. Adding rail tariffs, terminal charges, and vessel expenses, transportation prices under the Mixed Controls scenario fall from $52.75/t in 1985 to $49.70/t in 1991 before increasing with new capital expenditures to $50.15/t by 1996. Costs vary over the period, reflecting changes in coal volumes and capital recovery

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* Capital repayment factors are calculated from:

$$\text{capital expenditure} = \sum^{N} \frac{\text{repayment}_n}{(1 + r)^n}$$

where: r - is the discount rate (7.1% for vessel and terminal investments; 6.6% for rail investments).

N - is the period over which capital repayment is spread (10 years).

TABLE 9 ESTIMATED TRANSPORTATION PRICES FOR WESTERN CANADIAN BITUMINOUS COAL: MIXED CONTROLS SCENARIO

	Capital Expenditures (1985 $ millions)				Transportation Prices (1985 $/t)			
	Rail	Terminal	Vessel	Total	Rail*	Terminal	Vessel	Total
1985	0.0	0.0	0.0	0.0	40.00	5.75	7.0	52.75
1986	0.0	0.0	0.0	0.0	37.60	5.75	7.0	50.35
1987	0.0	0.0	0.0	0.0	37.60	5.75	7.0	50.35
1988	0.0	0.0	0.0	0.0	37.60	5.75	7.0	50.35
1989	0.0	0.0	0.0	0.0	37.60	5.75	7.0	50.35
1990	0.0	0.0	0.0	0.0	37.60	5.75	7.0	50.35
1991	0.0	0.0	0.0	0.0	37.00	5.70	7.0	49.70
1992	0.0	0.0	0.0	0.0	37.00	5.70	7.0	49.70
1993	0.0	0.0	0.0	0.0	37.00	5.70	7.0	49.70
1994	29.0	0.0	0.0	29.0	37.00	5.70	7.0	49.70
1995	29.0	0.0	0.0	29.0	37.00	5.70	7.0	49.70
1996	0.0	0.0	0.0	0.0	38.50	4.65	7.0	50.15
1997	29.0	0.0	0.0	29.0	38.50	4.65	7.0	50.15
1998	14.5	0.0	0.0	14.5	38.50	4.65	7.0	50.15
1999	29.0	0.0	0.0	29.0	38.50	4.65	7.0	50.15
2000	0.0	0.0	0.0	0.0	38.50	4.65	7.0	50.15
Present Value	63.3	0.0	0.0	63.3	-	-	-	-

* includes capital repayment for new investments

expenses. Transportation prices are most strongly influenced by rail charges, which account for over 75% of the total cost.

Western Canadian Coal Control Scenario. Transporting 14.12 x 10^6 t/yr of western Canadian bituminous coal requires considerable investment in train sets, the Thunder Bay terminal, and vessels. Specifically, 20 additional train sets are needed. At $14.5 million/set total costs are about $139 million (discounted), with construction and purchases in the following years:

1994 - 3 train sets,
1995 - 3 train sets,

1996 - 4 train sets,
1997 - 2 train sets,
1998 - 4 train sets, and
1999 - 4 train sets.

Including the amortized cost of these capital expenditures, rail tariffs are estimated to rise from $37.70/t (1991 to 1995) to $39.20/t (1996 to 2000). Prices decline from 1985 to 1995 because large capital repayments on existing train sets are completed by 1988. In accordance with the likely practice on long-term supply contracts, prices have been averaged over five-year intervals.

The Thunder Bay terminal requires rail extensions and a second set of unloading equipment, costing $35 million in 1996 to 1997 ($16.3 million in present value terms). Handling charges remain at $5.75/t until 1991, gradually falling to $3.65/t as capital repayments (on new and existing capital) are spread out over larger coal volumes.

Water movement of bituminous coal under the WCC Control scenario requires ten more vessels. It is assumed five vessels become available from the existing fleet (including vessels currently used to ship U.S. coal) and five new vessels are built. Each new vessel costs approximately $45 million and requires two years to construct. The present value of vessel costs is about $100 million. Construction and initial use of new vessels would be:

Number of Vessels	Construction	Initial Use
1	1996 to 1997	1998
2	1997 to 1998	1999
2	1998 to 1999	2000

Vessel charges are estimated to rise substantially from the $7.00/t base price to $9.15/t between 1996 and 2000, reflecting these large incremental capital costs.

Capital expenditures and transportation prices under the WCC Control option are presented in Table 10. Capital costs amount to $255 million, consisting primarily of expenditures on new rail and vessel units ($138.6 million and $100.1 million respectively). Capital expenditures are concentrated in the three-year period from 1997 and 1999 which reflects the rapid rise in demand for western Canadian bituminous coal in the late 1990's.

Total transportation prices for the WCC Control scenario are also presented in Table 10. Prices initially fall from the 1985 level of $52.75/t to $50.25/t between 1991

TABLE 10 ESTIMATED TRANSPORTATION PRICES FOR WESTERN CANADIAN BITUMINOUS COAL: WCC CONTROL SCENARIO

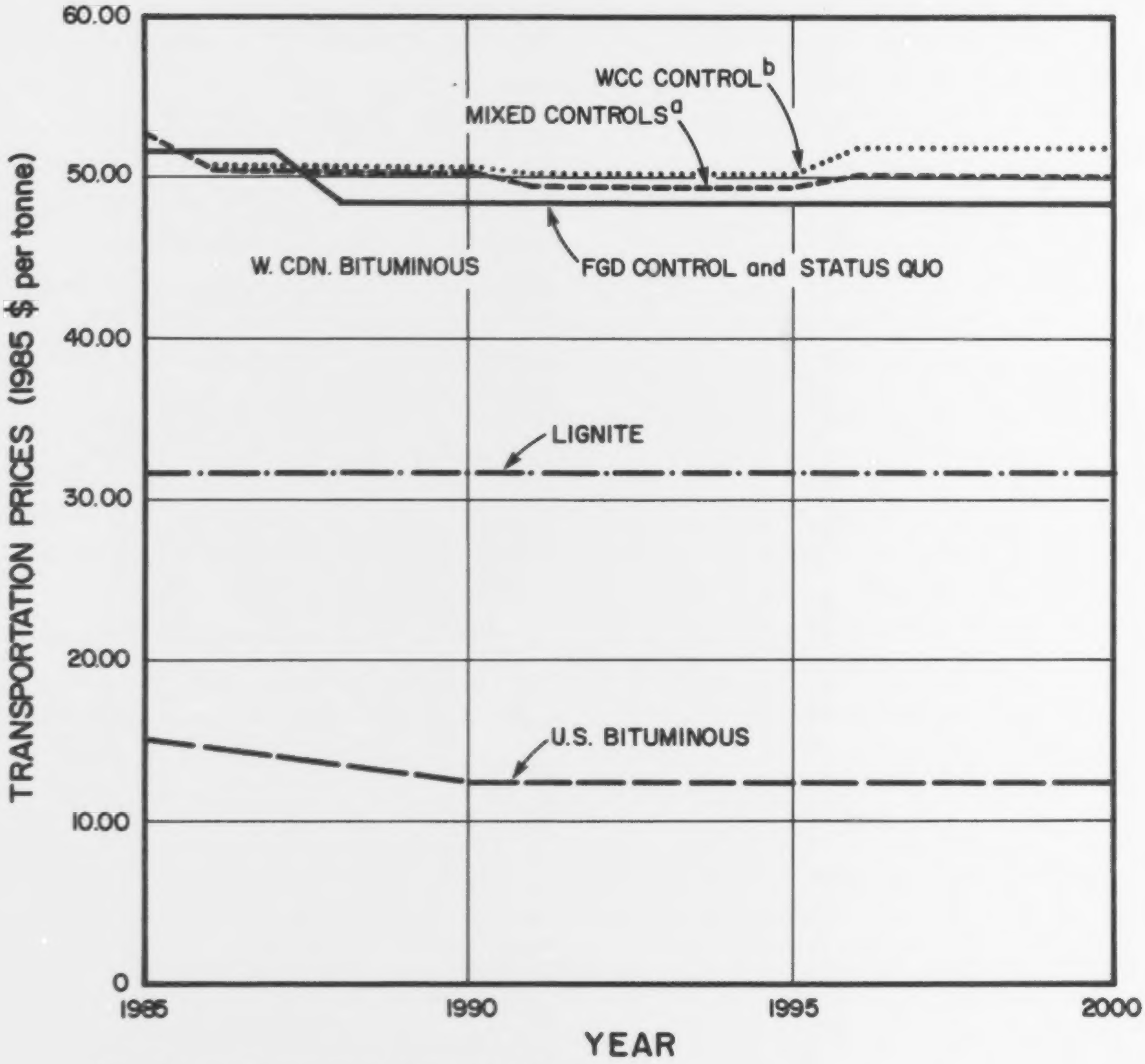
	Capital Expenditures (1985 $ millions)				Transportation Prices (1985 $/t)			
	Rail	Terminal	Vessel	Total	Rail*	Terminal	Vessel*	Total
1985	0.0	0.0	0.0	0.0	40.00	5.75	7.0	52.75
1986	0.0	0.0	0.0	0.0	37.90	5.75	7.0	50.65
1987	0.0	0.0	0.0	0.0	37.90	5.75	7.0	50.65
1988	0.0	0.0	0.0	0.0	37.90	5.75	7.0	50.65
1989	0.0	0.0	0.0	0.0	37.90	5.75	7.0	50.65
1990	0.0	0.0	0.0	0.0	37.90	5.75	7.0	50.65
1991	0.0	0.0	0.0	0.0	37.70	5.55	7.0	50.25
1992	0.0	0.0	0.0	0.0	37.70	5.55	7.0	50.25
1993	0.0	0.0	0.0	0.0	37.70	5.55	7.0	50.25
1994	43.5	0.0	0.0	43.5	37.70	5.55	7.0	50.25
1995	43.5	0.0	0.0	43.5	37.70	5.55	7.0	50.25
1996	58.0	9.0	22.5	89.5	39.20	3.65	9.15	52.00
1997	29.0	17.0	67.5	113.5	39.20	3.65	9.15	52.00
1998	58.0	9.0	90.0	157.0	39.20	3.65	9.15	52.00
1999	58.0	0.0	45.0	103.0	39.20	3.65	9.15	52.00
2000	0.0	0.0	0.0	0.0	39.20	3.65	9.15	52.00
Present Value	138.6	16.3	100.1	255.0	-	-	-	-

* includes capital repayment for new investments

and 1995 as repayment on existing capital is completed. After 1995, however, capital repayment requirements cause prices to increase to $52.00 by 1996.

2.2.3 Summary of Transportation Prices. Overall transportation prices are lowest for U.S. coal and lignite (Figure 5). Although U.S. coal prices decline over time with exchange rate adjustments, neither lignite nor U.S. prices vary among the scenarios.

By contrast, transportation prices for western Canadian bituminous coal depend on capital expenditures on new equipment and facilities and, therefore, differ by scenario. Transportation prices for western Canadian bituminous coal are highest under the WCC Control scenario at $52.00/t from 1996 to 2000, which reflects capital expenses



[a] Includes capital repayment for nine new train sets.

[b] Includes capital repayment for twenty new train sets, expansion of Thunder Bay terminal and five new vessel.

Note: All prices in Canadian dollars.

FIGURE 5 SUMMARY OF ESTIMATED TRANSPORTATION PRICES 1985 to 2000 (1985 $/tonne)

of $255 million. Under the Mixed Controls scenario, transportation prices also rise in 1996. This increase is associated with capital expenditures on new train sets totalling $63.3 million over the 16-year period. Fluctuations in transportation costs over time are caused by variations in capital repayments or coal volumes.

No capital expenses or volume penalties are incurred under either the FGD Control or Status Quo scenarios. Transportation prices for western Canadian bituminous coal under these scenarios, therefore, remain at $52.75/t until 1988 and at $48.75/t over the rest of the period. These transportation prices do not include any factor for volume discounts. However, it is very likely that prices could be negotiated downwards. Price flexibility is particularly likely under the WCC Control scenario which generates a sevenfold increase in coal volumes shipped between 1985 and 2000.

2.3 Summary of Delivered Coal Prices

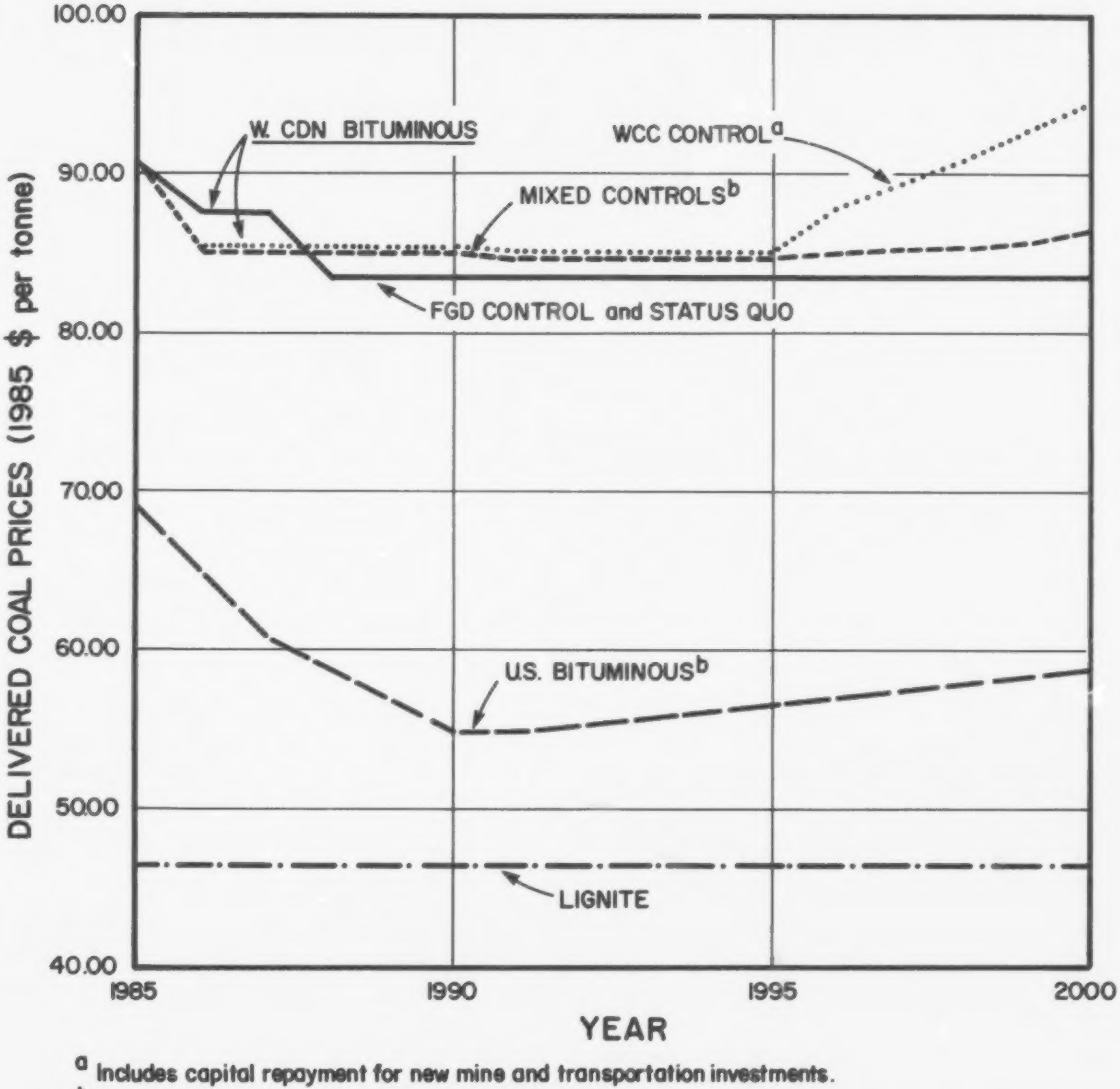
The price of coal delivered at Ontario Hydro generating stations is critical to the cost evaluations of each coal use scenario. Delivered coal prices are made up of the mine and transportation prices previously developed. Profiles for delivered coal prices for each coal type are illustrated in Figure 6, based on the annual data found in Table 11.

The combination of projected declines in mine prices (based on expected heavy oil prices) and a drop in the foreign exchange rate causes a substantial drop in U.S. coal prices over the period 1985 to 1990. Even with a real price increase of 1% per year between 1990 and 2000, the U.S. delivered price rises only to about $59.35/t by the year 2000, more than $10.00/t below the 1985 price.

The price of western Canadian lignite is assumed to stay constant at $46.35/t throughout the period for all scenarios.

The delivered price of western Canadian bituminous coal is significantly higher than either lignite or U.S. coal. Furthermore, the price of western Canadian bituminous coal is expected to rise under both the Mixed Controls and WCC Control scenarios from 1986 levels. In the WCC Control option the delivered price rises sharply between 1996 and 2000 to $94.20/t. New capital investments in transportation and mine capital must be repaid. The average delivered price over the 1996 to 2000 year period is $91.50/t or about $5.85/t higher than the 1986 base.

The delivered price of western Canadian bituminous coal under the Mixed Control scenario also reflects capital expenditures and changes in coal volumes. Investment in train sets and mine expansions raise the price from about $85.35/t in 1986 to



[a] Includes capital repayment for new mine and transportation investments.

[b] Incorporates changes in mine price and exchange rate

Note: All prices in Canadian dollars

FIGURE 6 SUMMARY OF ESTIMATED DELIVERED COAL PRICES 1985 to 2000 (1985 $/tonne)

TABLE 11 ESTIMATED DELIVERED COAL PRICES 1985 to 2000 (1985 $/t)

Year	U.S. Coal (all scenarios)	W. Canadian Lignite (all scenarios)	Western Canadian Bituminous			
			FGD Scenario	Status Quo Scenario	Mixed Control Scenario	WCC Control Scenario
1985	69.45	46.35	90.75	90.75	90.75	90.75
1986	65.15	46.35	87.75	87.75	85.35	85.65
1987	61.10	46.35	87.75	87.75	85.35	85.65
1988	59.00	46.35	83.75	83.75	85.35	85.65
1989	56.85	46.35	83.75	83.75	85.35	85.65
1990	54.90	46.35	83.75	83.75	85.35	85.65
1991	55.35	46.35	83.75	83.75	84.70	85.25
1992	55.75	46.35	83.75	83.75	84.70	85.25
1993	56.20	46.35	83.75	83.75	84.70	85.25
1994	56.65	46.35	83.75	83.75	84.70	85.25
1995	57.05	46.35	83.75	83.75	84.70	85.25
1996	57.50	46.35	83.75	83.75	85.35	87.50
1997	57.95	46.35	83.75	83.75	85.45	89.20
1998	58.40	46.35	83.75	83.75	85.55	90.50
1999	58.85	46.35	83.75	83.75	85.95	92.70
2000	59.35	46.35	83.75	83.75	86.85	94.20

$86.85/t in the year 2000. The average delivered price of western Canadian bituminous coal is $86.80/t between 1996 and 2000 under this scenario, or about $1.45/t higher than the 1986 base.

Delivered coal prices are based on a number of assumptions made by the Task Force. Different assumptions may significantly affect cost comparisons among the coal use scenarios. Opportunities to lower Canadian coal prices by reducing coal costs in one or more contributing sectors may be identified with further investigation. Alternative criteria might be used in making the coal prices projections (e.g., limitations could be placed on the extent to which U.S. coal prices will follow heavy oil price trends). Sensitivity analyses of alternative coal price profiles were performed to determine the potential effect of delivered coal price variations on the private and social costs of each coal use scenario. The results are discussed in later subsections and estimates of incremental fuel costs that follow are based on the price profiles in Table 11.

Total delivered coal costs are calculated from the delivered fuel prices presented and coal volumes previously outlined. Incremental coal costs are the difference between total delivered coal costs under each coal use scenario and total delivered coal costs under a "no control" option. Ontario Hydro is assumed to eliminate consumption of western Canadian bituminous coal by 1993 in the absence of control requirements, following the same pattern of coal demand as under the FGD Control option.

Incremental fuel costs for the period from 1985 to the year 2000 are illustrated in present value terms in Figure 7. The (small) incremental fuel costs under the FGD Control scenario arise from an energy penalty associated with FGD.

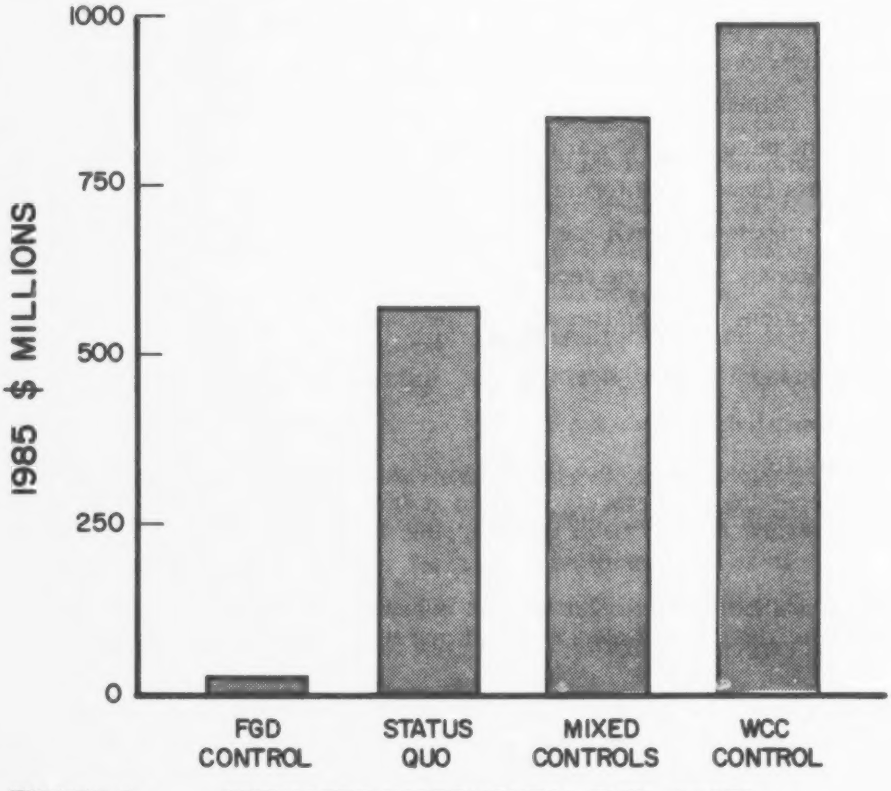


FIGURE 7 ESTIMATED INCREMENTAL FUEL COSTS (1985, $ millions, present value 1985 to 2000)

Incremental costs are highest ($982 million) under the WCC Control scenario, reflecting considerably higher consumption of (more expensive) western Canadian bituminous coal after 1993 than under the "no control" case. Under the Mixed Control scenario, consumption of western Canadian coal is higher than under the "no control" case in every year, with incremental coal costs amounting to $846 million in present value terms. Incremental coal costs are $558 million under the Status Quo scenario.

2.4 Station Modification Costs (excluding acid gas emission control equipment)

2.4.1 Basis of Cost Estimates. Monenco Ltd. estimated order-of-magnitude costs for modifications to station coal handling and combustion systems required to burn low sulphur western Canadian bituminous coal under each of the four scenarios.

Development of costs was constrained by the amount of design information available. Assumptions had to be made which, in some cases, may not correspond exactly to design conditions. It was understood that existing design margins should not be seriously reduced, which introduced a need for judgement in deriving cost estimates.

In general, costs were developed according to experience with generating stations built in Western Canada in the last few years and from discussions with boiler manufacturers. Conditions peculiar to Ontario were not taken into account, except: the cost of coal blending plants (based on information provided during a meeting with Ontario Ministry of Environment representatives); and the cost of shipping docks (developed from a recent overseas study; Monenco in-house report).

General assumptions and premises used in the following cost analysis are:

- plant capacity factor is 65% for all cases;
- all retrofits are physically possible;
- when a mixture of coals is used, two docks for coal vessels are necessary, each requiring a coal receiving and storing system; a blending plant is also required (Nanticoke and Lakeview already have two shipping docks; Nanticoke already has a blending plant);
- unless there is doubt about a particular item or subsystem, the coal reclaim system capacity is considered adequate (i.e., a reduced margin would still leave a workable system);
- although burning western Canadian bituminous coal requires longer furnace residence time than eastern U.S. coal, the resultant increase in unburnt carbon is not considered sufficient to change a boiler;
- the ash plant capacity is considered sufficient for Lambton and Lakeview, although the number of trucks increases; for Nanticoke, changes to be introduced are described later;
- coal piles are enlarged to maintain winter supply conditions, but the availability or purchase of extra land is not considered in the cost estimates; and

- O&M and energy costs related to increased systems utilization are accounted for.

2.4.2 Station Modification Costs by Scenario.

FGD Control Scenario. The 4000 MW Nanticoke station on Lake Erie presently burns a 50/50 blend of western Canadian bituminous and U.S. coals. The Nanticoke plant has a separate ship port, coal transfer facility, storage area, and large blending facility. No combustion or coal handling modifications are required for declining volumes of Canadian coal demand as assumed uner the FGD Control scenario.

Status Quo Scenario. In the Status Quo scenario, two units at Nanticoke are switched from 50/50 blends to 100% western Canadian coal, necessitating boiler and coal and ash system modifications and new electrostatic precipitators (ESPs). Although the two Nanticoke units do not need to be operated with 100% western Canadian coal until the year 2000, modifications are undertaken in 1992 and 1993 to ensure adequate coal-fired generating capacity is available throughout the 1990s.

In addition, it is assumed that electrostatic precipitators on generating units burning 100% western Canadian coal are replaced with precipitators properly sized for the lower sulphur and sodium content of western coals in order to meet particulate emission controls. Prices for these replacements and associated ductwork are estimated at $42 million/unit*. Precipitator upgrades will also be required.

Total (discounted) capital expenditures under the Status Quo scenario are $60.7 million, with associated incremental annual costs (including O&M capital repayment) of $38.0 million.

Mixed Controls Scenario. In both the Mixed Controls and WCC Control scenarios, boiler modifications are required. Combustion Engineering (CE) and Babcock & Wilcox (B&W) are the boiler manufacturers for the three generating stations, both companies having supplied 500 and 300 MW units. The companies were asked to carry out a short study on the feasiblity and costs for modifications on existing boilers to conform to the various scenarios.

Combustion Engineering (CE) manufactured four 500 MW boilers at Lambton and two 300 MW boilers at Lakeview. Conbustion Engineering representatives indicated that pulverizers have to be changed for scenarios where use of western Canadian coal is expanded. Fan working conditions also have to be uprated from design conditions (1% to 9% in static pressure, 3% to 35% in volume flow, and 4% to 50% in horsepower). Not knowing the available design margins, some cost was attributed to rework on small upratings and motor and/or fan changes.

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* The cost of these precipitators has been estimated based on coals with low-sulphur (order of 0.3%), medium ash (about 14%), and low sodium (typical 0.3% Na_2O as percentage of ash analysis).

According to CE, no changes in air preheaters, burner, windboxes, fuel pipes, and sootblowers are necessary. More frequent sootblowing could be needed but no increase in fouling or slagging is anticipated. Erosion increases, but remains within design limits and there is no need for additional erosion shields.

Babcock and Wilcox manufactured eight 500 MW boilers at Nanticoke and six 300 MW boilers at Lakeview. As with Combustion Engineering, possible variations in coal characteristics required caution in the design appraisal.

Using the Babcock and Wilcox boilers, design modifications for all scenarios are more extensive than for CE. New pulverizers, primary air (PA) fans, PA preheaters, and burners or burner throats may be required to attain Maximum Capacity Rating (MCR) conditions, although some western Canadian coals would require few design changes.

Under the Mixed Controls scenario, the Lakeview and Lambton generating stations remain on 100% U.S. bituminous coal throughout the period, requiring only FGD installation (see Section 2.5). However, as Nanticoke gradually switches from a 50/50 blend to 100% western Canadian bituminous coal, modifications to boilers and to coal and ash systems are required.

Capital expenditures on these investments total (on a present value basis) $213.8 million. Incremental operating and maintenance costs (excluding capital recovery) associated with the modifications rise from about $800 000 in 1995 to $5.7 million by the year 2000. Including capital recovery, annual incremental station costs rise to $37.6 million by the year 2000. Over the study period (discounted) annual costs amount to $147.4 million.

Western Canadian Coal Control Scenario. Under the WCC Control scenario, all four units at Lambton and all eight units at Nanticoke plus two units at Lakeview are converted to burn 100% western Canadian coal by the year 2000. The other six Lakeview units continue to burn only U.S. coal throughout the planning period.

Because boilers are burning either 100% U.S. or 100% western Canadian coal, no port or blending facilities are required at either Lakeview or Lambton. Existing coal handling and blending facilities at Nanticoke are adequate for interim years when 50/50 blends are burned.

Units that are converted to burn 100% western Canadian coal require fairly extensive modifications to coal, ash and boiler systems. Precipitator upgrades will also be required.

Station modifications occur between 1991 and 1994 to minimize the number of units out of service in the late 1990s and to ensure adequate system generating capacity. Total present value of station capital costs under the WCC Control scenario is $371.7 million; $59.0 million for combustion (boiler, coal and ash systems) and $312.7 million for ESP.

Incremental annual costs associated with these expenditures (including O&M and capital recovery) rise from $9.2 million in 1991 to $67.0 million in the year 2000. Total incremental station costs discounted over the 16-year period are estimated at $256.7 million.

2.4.3 Summary of Station Modification Costs. Table 12 summarizes capital expenditures for station modifications for all four scenarios. Estimates for both the Mixed Controls and WCC Control scenarios reflect capital investments for boiler, coal and ash modifications and ESP upgrades totalling $213.8 million and $371.7 million, respectively (in present value terms). The burden of these investments is exacerbated by their timing — modifications are initiated in 1991 and completed three years later. Because boilers must be taken out of service for some modifications, this short timetable is necessary to ensure adequate coal-fired generating capacity is available as needed in the late 1990s. No capital investments are required under the FGD Control scenario.

Capital repayment accounts for most of the incremental annual costs at the station. Consequently, annual costs for station modifications are highest under the WCC Control scenario, being $256.7 million in present value terms compared with $147.4 million under the Mixed Controls scenario. Annual costs are $38.0 million under the Status Quo scenario and zero for the FGD Control scenario (Table 13).

2.5 Acid Gas Emission Control Equipment Costs

2.5.1 Basis of Cost Estimates. Monenco Ltd. estimates the capital costs of FGD at $136 million per 500 MW unit at both Nanticoke and Lambton stations, based on an EPRI economic evaluation of FGD systems for a limestone process with forced oxidation (EPRI, 1981). Capital costs for 300 MW units at Lakeview are estimated at $100 million per unit. Adjustments are made for capacity (where applicable), currency exchange, escalation, and retrofit penalty).

TABLE 12 COMPARISON OF ESTIMATED CAPITAL COSTS FOR STATION MODIFICATIONS (1985 $ millions)

	Scenario			
	FGD Control	Status Quo*	Mixed Controls*	WCC Control*
1985	0.0	0.0	0.0	0.0
1986	0.0	0.0	0.0	0.0
1987	0.0	0.0	0.0	0.0
1988	0.0	0.0	0.0	0.0
1989	0.0	0.0	0.0	0.0
1990	0.0	0.0	0.0	0.0
1991	0.0	0.0	97.0	97.0
1992	0.0	49.0	97.0	198.5
1993	0.0	49.0	97.0	198.5
1994	0.0	0.0	49.0	106.0
1995	0.0	0.0	0.0	0.0
1996	0.0	0.0	0.0	0.0
1997	0.0	0.0	0.0	0.0
1998	0.0	0.0	0.0	0.0
1999	0.0	0.0	0.0	0.0
2000	0.0	0.0	0.0	0.0
Present Value	**0.0**	**60.7**	**213.8**	**371.7**

* modifications to boiler, coal and ash handling systems and new precipitators

TABLE 13 COMPARISON OF ESTIMATED ANNUAL COSTS FOR STATION MODIFICATIONS* (1985 $ millions)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
1985	0.0	0.0	0.0	0.0
1986	0.0	0.0	0.0	0.0
1987	0.0	0.0	0.0	0.0
1988	0.0	0.0	0.0	0.0
1989	0.0	0.0	0.0	0.0
1990	0.0	0.0	9.1	0.0
1991	0.0	0.0	9.1	9.2
1992	0.0	4.5	18.3	27.9
1993	0.0	8.9	27.4	46.5
1994	0.0	8.9	31.9	58.1
1995	0.0	8.9	32.8	59.8
1996	0.0	8.9	33.5	61.5
1997	0.0	8.9	35.2	63.2
1998	0.0	8.9	35.2	64.0
1999	0.0	8.9	36.8	66.0
2000	0.0	10.5	37.6	67.0
Present Value	**0.0**	**38.0**	**147.4**	**256.7**

* includes capital repayment and O&M

2.5.2 Emission Control Equipment Costs by Scenario. Flue gas desulphurization requirements are determined by the volume of high-sulphur U.S. coal used and where it is burned. FGD costs therefore, vary across scenarios.

FGD Control Scenario. To meet new emission guidelines while burning only lignite and U.S. coal, FGD is required on all twelve 500 MW units at Nanticoke and Lambton generating stations and on three 300 MW units at Lakeview by the year 2000. Installation is assumed to begin in 1991, with the first unit on stream in 1994. The last three units begin operation in the year 2000. Total (present value) capital costs under the FGD Control scenario is about $996.3 million.

Operation and maintenance costs for a 500 MW FGD unit are estimated at about $8.3 million, and $6 million per year for a 300 MW FGD unit. Total incremental annual costs for acid gas emission control, which include repayment for new capital and incremental O&M costs, rise from $4.1 million in 1991 (first year of capital repayment) to $81.0 million in 1994 (first year of operation) and to $294.6 million in the year 2000. The present value of incremental annual costs (including O&M and capital recovery) is $625.6 million over the planning period.

Status Quo Scenario. Under the Status Quo scenario, FGD is necessary on all units at Lambton and Lakeview and on three units at Nanticoke. (The remaining five units at Nanticoke continue to burn a 50/50 blend of western Canadian and U.S. coal.) FGD on 300 MW units at Lakeview cost $100 million each, compared with $136 million for each 500 MW unit at Lambton. Installation begins in 1992 and is completed by 1999. Operation of the first unit begins in 1995. Total (present value) capital expenditures on FGD under the Status Quo scenario are $865.6 million.

Incremental annual costs (including capital recovery and O&M) amount to $471.2 million (present value over the entire period), based on operation and maintenance costs of $8.3 million per unit per year at Nanticoke and Lambton and $6.0 million per unit per year at Lakeview.

Mixed Controls Scenario. Notwithstanding expanded use of western Canadian coal, FGD is required on all units at Lambton and on five units at Lakeview by the year 2000. Installation begins in 1993 with initial use in 1996. Based on unit costs of $136 million at Lambton and $100 million at Lakeview, total (present value) acid gas emission control equipment costs are $502.7 million. Incremental annual costs (including capital repayment and O&M) rise from $4.1 million in 1993 to $158.7 million in the year 2000, totalling $263.3 million (discounted) over the 16-year period.

Western Canadian Coal Control Scenario. By definition, no FGD is required under this scenario.

2.5.3 Summary of Costs of Acid Gas Emission Control Equipment. Tables 14 and 15 compare the capital and incremental annual costs of acid gas emissions control equipment under the four coal use scenarios. Total (discounted) capital and annual costs are highest under the FGD Control option, reflecting:

- the high cost of FGD equipment;
- installation of all 500 MW units; and
- initial use of FGD as early as 1994.

The major cost advantage of expanded use of western Canadian coal is the postponement, reduction, or elimination of FGD costs. This benefit is most dramatically

TABLE 14 COMPARISON OF ESTIMATED CAPITAL EXPENDITURES FOR ACID GAS EMISSION CONTROL EQUIPMENT (1985 $ millions)

	Scenario			
	FGD Control*	Status Quo**	Mixed Controls***	WCC Control
1985	0.0	0.0	0.0	0.0
1986	0.0	0.0	0.0	0.0
1987	0.0	0.0	0.0	0.0
1988	0.0	0.0	0.0	0.0
1989	0.0	0.0	0.0	0.0
1990	0.0	0.0	0.0	0.0
1991	45.3	0.0	0.0	0.0
1992	113.4	45.3	0.0	0.0
1993	249.3	113.4	45.3	0.0
1994	272.0	249.3	90.7	0.0
1995	272.0	286.0	158.7	0.0
1996	272.0	250.0	181.3	0.0
1997	272.0	250.0	218.0	0.0
1998	286.0	354.0	250.0	0.0
1999	150.0	204.0	100.0	0.0
2000	0.0	0.0	0.0	0.0
Present Value	**996.3**	**865.6**	**502.7**	**0.0**

* FGD required on twelve 500 MW units at Nanticoke and Lambton and on three 300 MW units at Lakeview

** FGD required on seven 500 MW units at Lambton and Nanticoke and eight 300 MW units at Lakeview

*** FGD required on four 500 MW units at Lambton and five 300 MW units at Lakeview

TABLE 15 COMPARISON OF ESTIMATED ANNUAL COSTS FOR ACID GAS EMISSION CONTROL EQUIPMENT* (1985 $ millions)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
1985	0.0	0.0	0.0	0.0
1986	0.0	0.0	0.0	0.0
1987	0.0	0.0	0.0	0.0
1988	0.0	0.0	0.0	0.0
1989	0.0	0.0	0.0	0.0
1990	0.0	0.0	0.0	0.0
1991	4.1	0.0	0.0	0.0
1992	14.7	4.1	0.0	0.0
1993	37.6	14.5	4.1	0.0
1994	81.0	37.3	12.4	0.0
1995	120.6	70.1	27.0	0.0
1996	162.0	109.5	51.9	0.0
1997	203.5	154.4	88.4	0.0
1998	246.2	194.8	119.5	0.0
1999	276.6	231.4	146.7	0.0
2000	294.6	256.4	158.7	0.0
Present Value	**625.6**	**471.2**	**263.0**	**0.0**

* includes capital repayment and O&M

illustrated by the absence of acid gas emissions control equipment requirements under the WCC Control option.

Under both the Status Quo and Mixed Controls scenarios, FGD units are required on a combination of units at Lakeview, Lambton and Nanticoke, although they are not installed or operational until later in the planning period. Capital and annual costs, therefore, are lower than under the FGD Control scenario.

2.6 Costs to Ontario Hydro of Reducing Acid Gas Emissions (private costs)

2.6.1 Comparison of Costs. Tables 16 to 18 compare capital and annual expenditures for reducing acid gas emissions under the four coal use scenarios. The costs are the sum of incremental coal costs delivered at Ontario Hydro, station modifications costs, and FGD costs, as developed in previous sections.

Within the margin of error for this study, total capital costs are similar for the Mixed Controls, FGD and WCC Control options (Table 16). Costs are lowest for the Mixed Controls ($824 million), reflecting lower FGD costs.

TABLE 16 COMPARISON OF INCREMENTAL CAPITAL EXPENDITURES FOR REDUCING ACID GAS EMISSIONS (private costs) (1985 $ millions, present value)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Mine	0	0	44	310
Transportation	0	0	63	255
Fuel Expenditures	**0**	**0**	**107**	**565**
Station Modifications*	0	61	214	372
FGD Costs	996	865	503	0
Station Expenditures	**996**	**926**	**717**	**372**
TOTAL EXPENDITURES	**996**	**926**	**824**	**937**

* includes electrostatic precipitators

Station modification requirements, for which Ontario Hydro would be directly responsible, are highest under the FGD Control option. Total capital expenditures under this scenario are $996 million (discounted) over the planning period. These costs cover construction and installation of FGD on twelve 500 MW units at Lambton and Nanticoke and on three 300 MW units at Lakeview.

FGD capital expenditures are lower under the Status Quo and Mixed Controls scenarios where less FGD capacity is required to meet the limits. FGD is required on seven 500 MW units at Lambton and Nanticoke and eight 300 MW units at Lakeview under the Status Quo scenario instead of twelve 500 MW units at Nanticoke and Lambton and three 300 MW units at Lakeview under the FGD Control case. The Mixed Controls scenario requires FGD on only four 500 MW units at Lambton and five 300 MW units at Lakeview.

Capital expenditures under the WCC Control scenario include costly mine developments, investments in new train sets and lakers and terminal expansions, as well as modifications to boilers, coal and ash handling systems and precipitators at the station. Total (discounted) costs under the WCC Control scenario are $937 million.

Table 17 presents discounted annual costs of reducing acid gas emissions. Annual costs include:

TABLE 17 COMPARISON OF TOTAL ESTIMATED COSTS TO ONTARIO HYDRO OF REDUCING ACID GAS EMISSIONS* (1985 $ millions, present value)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Incremental Fuel Costs	**29**	**558**	**846**	**1024**
Station Modifications	0	38	147	256
FGD Costs	625	471	263	0
Incremental Station Costs	**625**	**509**	**410**	**256**
Costs of Reducing Emissions	**654**	**1067**	**1256**	**1280**
Difference from FGD Control	n/a	+63%	+92%	+96%
SO_2 and NO_x removed (kt)	1625	1861	1861	1625

* includes capital repayment and incremental operation and maintenance expenses

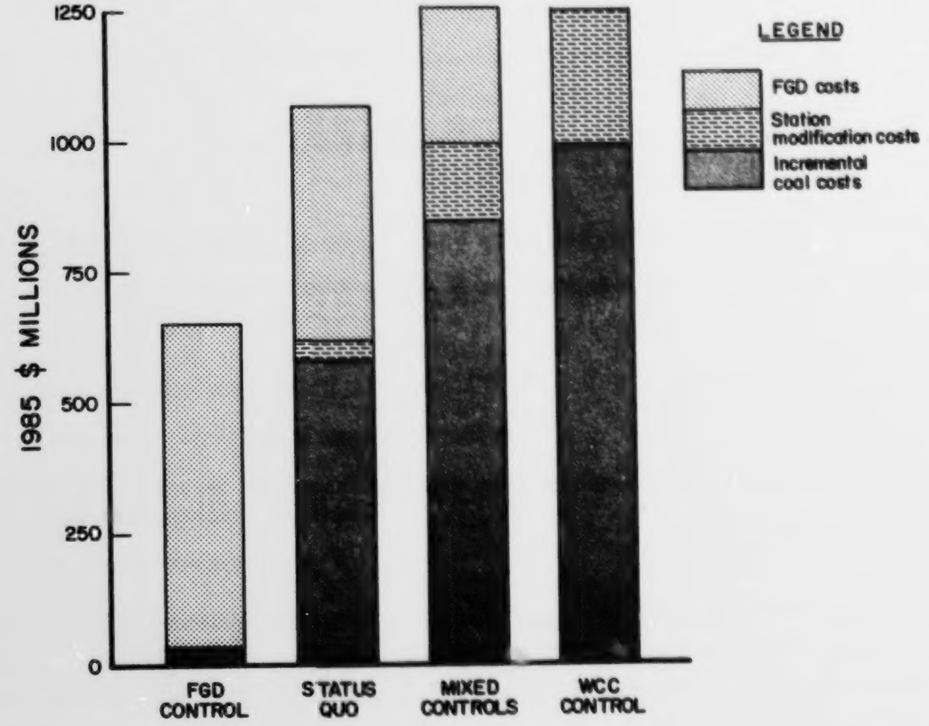

TABLE 18 ESTIMATED ANNUAL COSTS TO ONTARIO HYDRO AND ASSOCIATED REDUCTIONS IN ACID GAS EMISSIONS

	Scenario							
	FGD Control		Status Quo		Mixed Controls		WCC Control	
	$ millions*	kt**	$ millions*	kt**	$ millions*	kt**	$ millions*	kt**
1985	0	0	0	0	0	0	0	0
1986	0	0	15	11	9	11	-4	0
1987	0	0	27	20	22	20	-3	0
1988	0	0	36	30	40	30	3	0
1989	0	0	41	36	45	36	2	0
1990	0	0	43	33	47	33	2	0
1991	4	0	59	22	70	22	11	0
1992	15	0	34	17	46	17	29	0
1993	38	0	121	52	132	52	47	0
1994	83	54	132	69	132	69	133	54
1995	75	108	166	108	190	108	207	108
1996	169	175	207	175	260	175	297	175
1997	213	231	252	231	315	231	397	231
1998	259	287	298	287	369	287	470	287
1999	291	350	348	350	428	350	584	350
2000	312	420	385	420	484	420	702	420
Present Value	654	-	1067	-	1256	-	1280	-
Total	-	1625	-	1861	-	1861	-	1625

* includes incremental fuel costs, capital repayment and operation and maintenance for station modifications and FGD investments

** SO_2 and NO_x removed

- incremental cost of U.S., western Canadian bituminous, and lignite coals (which themselves include operation and maintenance and a factor for capital repayment for new mine and transportation investments);
- capital repayment for station and FGD modifications; and
- incremental operating and maintenance costs associated with station modifications and FGD.

Incremental costs for the Mixed Controls scenario are estimated at $1.256 billion, almost double the $654 million cost of FGD using U.S. coal. Higher costs arise from incremental fuel costs, capital and operating expenses of station modifications, combined with FGD requirements.

Although incremental station costs are lower under the Status Quo scenario than scenarios using the FGD scenario, additional fuel costs of about $558 million raise the overall cost of this option to $1.067 billion, about 63% higher than the cost of FGD with U.S. coal.

The Status Quo and Mixed Controls scenarios remove 15% more SO_2 and NO_x emissions than either of the other two abatement scenarios. The most valid comparison of the cost of just meeting emission limits is between the FGD and WCC Control scenarios, both which remove the same amount of acid gas emissions over the same time frame.

As indicated in Table 17, lower incremental station costs under the WCC Control scenario are not sufficient to offset substantially higher fuel costs than under the FGD Control scenario. Overall, the cost to Ontario Hydro of reducing acid gas emissions through expanded use of western Canadian coal is $1.280 billion — 96% higher than the FGD Control costs of $654 million.

2.6.2 **Sensitivity Analysis.** Because many assumptions have been used to estimate the costs of reducing acid gas emissions, the Task Force evaluated the sensitivity of the estimates to variations in:

- delivered U.S. coal prices;
- delivered western Canadian bituminous coal prices;
- increased quantities of western Canadian coal to partially compensate for derating of generating station boilers; and
- FGD capital and operating costs.

(a) Variation in Delivered Price of U.S. Coal. The two major assumptions underlying the base price profile for U.S. coal are:

1) the foreign exchange rate drops to a 20-year average of 1.15 by 1990; and
2) mine prices for U.S. coal follow projections for changes in heavy oil prices during the period 1985 to the year 2000.

Two different price profiles for delivered U.S. coal are examined to assess the implications of changing these assumptions:

1) a profile based on assumption that the foreign exchange rate will remain at its current (February, 1986) rate, but U.S. coal mining prices will still vary with heavy oil prices; and
2) a level profile (price constant at $69.94) which assumes the foreign exchange rate remains constant and U.S. coal mining prices do not vary with heavy oil prices.

b) Variation in Western Canadian Bituminous Coal Prices. Western Canadian bituminous coal prices could be affected by changes in assumptions in the mining sector and each of the transportation stages; rail, terminal and vessel. For example, there may be justification in assuming Canadian mining prices would follow the U.S. heavy oil price trends, or that transportation prices may be reduced through negotiations, especially where shipment volumes increase significantly.

Given that there may be opportunities for reducing the overall delivered price of western Canadian bituminous coal, sensitivity tests were run to compare costs of each coal use scenario at several coal prices below that assumed for the base estimates. The variations in western Canadian bituminous coal prices examined are:

1) continued drop in price from $90.75/t in 1985 to $80.00/t in 1989, then constant at $80.00/t to the year 2000;
2) continued drop in price from $90.75/t in 1985 to $75.00/t by 1989, then constant at $75.00/t to the year 2000;
3) continued drop in price from $90.75/t in 1985 to $65.00/t by 1990, then constant at $65.00/t to the year 2000.

In comparison, bituminous coal prices assumed for the base estimates were:

	FGD Control Scenario	WCC Control Scenario
1985	90.75	90.75
1986 to 1995	84.55	85.45
1995 to 2000	84.75	91.50 (avg.)

(c) Increased Coal Quantities to Account for Potential Boiler Derating. There is a distinct possibility that the design maximum power output will not be achieved from the generating units without major modifications to boilers and auxiliaries (over and above modifications assumed in the base estimates) if low-sulphur western bituminous coal is substituted completely for U.S. Appalachian high sulphur coal.

The designers of Ontario Hydro's boilers have been asked to comment and their replies have ranged from affirmation that the boiler capacity will not be affected to guarded non-committal reservations. The responses hinge in part on coal properties, which may never be completely defined because of the large quantities and diverse coal sources involved.

Because of the contradictory opinions from vendors and operators on the possibility and amount of derating of power output, no allowance was made in the base cost comparisons. Nevertheless, before increasing the use of western coal in boilers designed for eastern fuel, derating and boiler efficiency experience of U.S. utilities and Ontario Hydro itself must be further investigated.

Several U.S. electric power utilities have already been contacted. These include:

- Tennessee Valley Authority,
- American Electric Power,
- Northern States Power,
- Wisconsin Power and Light,
- Wisconsin Electric, and
- consultants for Minnesota Power.

The experience of these U.S. operators with western U.S. coal has been mostly negative. The boiler units have either had to be derated, sometimes to intolerable levels, or have undergone extensive internal and external changes. United States operators have also encountered operational difficulties in the performance of several important ancillary elements, such as pulverizers, sootblowers, air heaters, electrostatic precipitators, dust handling and transport, as well as problems with the boiler proper.

There has been no comparison of specific boiler designs at the U.S. stations with those at Ontario Hydro stations or of western U.S. and western Canadian bituminous coals; therefore, experience may not be directly transferable. The number of documented derating experiences, however, suggests there is a very real possibility of derating at the Ontario stations.

To assess the implications of derating on the comparison of the selected scenarios, cost analyses were conducted with western Canadian bituminous coal quantities increased by 10% from quantities assumed in the base analysis. This is not a complete assessment of the implication of derating, since neither the cost of generating capacity additions that may have to be made to replace lost generating capability or the capital investment required to supply the 10% coal increment (e.g., additional train sets) are taken into account.

(d) Variations in FGD Capital and Operating Costs. Finally, the costs of continued use of U.S. coal depend on the estimated capital and operating costs for FGD. Based on a submission by Monenco Consultants Ltd., (capital costs) and Environment Canada information (operating costs), the Task Force used the following assumptions:

	per 300 MW unit	per 500 MW unit
Capital Costs	$100 million	$136 million
Operating Costs	$6.0 million	$8.3 million

FGD capital and operating costs are, however, likely to vary by unit, location and design specifications. To examine the impact of FGD cost variations, sensitivity tests were performed using 20% higher and 20% lower FGD costs.

The results of each sensitivity test are presented in Table 19. Cost estimates from the base analysis (Task force Assumptions) are given for reference. For simplicity, tests were done for the FGD and WCC Control scenarios only as they represent the lowest and highest level of western Canadian coal use and are the most valid for comparison.

Because fuel use patterns are assumed to be the same under a "no control" case and the FGD control option, incremental fuel costs reflect only the energy penalty associated with FGD. Consequently, the cost of reducing acid gas emissions under this scenario is only marginally affected by any change in fuel prices, as embodied in most tests. The cost of the FGD Control option, therefore, ranges between $654 million and $661 million for all sensitivity tests, except for variations in FGD costs.

The cost of reducing acid gas emissions by expanded use of low-sulphur western Canadian coal is sensitive to changes in both U.S. and Canadian fuel prices. As indicated in Table 19, higher delivered prices for U.S. coal reduce the price differential between the two coal sources and, therefore, enhance the relative attractiveness of the WCC Control option. A constant U.S. coal price of $69.45/t reduces costs to about $1.06 billion, or 18% lower. Maintaining the exchange rate at current levels lowers the cost of the WCC Control option by about 20% to $1.03 billion.

TABLE 19 RESULTS OF SENSITIVITY TEST ON SELECTED PARAMETERS: COSTS TO ONTARIO HYDRO (1985 $ millions, present value 1985-2000)

	Cost of Reducing Acid Gas Emission	
	FGD Control Scenario	WCC Control Scenario
Task Force Assumptions	654	1280
(a) Variation in U.S. Coal Price		
1) coal price constant at Cdn. $69.45/t	661	1058
2) Feb. 1986 exchange rate	661	1031
(b) Variations Western Canadian Bituminous Coal Price		
1) $80.00/t after 1989	654	1028
2) $75.00/t after 1989	654	906
3) $65.00/t after 1990	654	665
(c) Boiler Derating		
1) 10% more western Canadian bituminous	654	1495
(d) FGD Costs		
1) 20% higher	780	1280
2) 20% lower	530	1280

Sensitivity tests on the price of western Canadian bituminous coal indicate that the WCC Control option becomes competitive with the FGD Control scenario at about $65/t. At that price, the cost of of WCC Control is $665 million. If, however, U.S. coal prices remained high (i.e., the current exchange rate prevails over the next 16 years), expanded use of western Canadian coal could be competitive with the FGD option at a price of $75.00/t. This conclusion is reached by combining the results of the sensitivity tests on the 1985 foreign exchange rate ((a) 2) in Table 19) and the test for coal prices at $75/t ((b) 2) in Table 19)*.

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* Maintenance of the current exchange rate reduces the cost of the WCC Control option by $249 million; a $75/t price reduces costs by $374 million. Combining both effects reduces the cost of the WCC Control option by $623 million to $657 million.

Favourable price changes could, however, be offset if expanded use of western Canadian bituminous coal causes boiler derating. As indicated in Table 19, a 10% increase in coal consumption caused by boiler derating increases the cost of the WCC Control scenario by 17% (from the Task force base estimates) to $1495 million. Because this does not include all of the possible derating costs, the total cost of boiler derating could exceed these amounts.

Finally, the cost differential between the FGD and WCC Control scenarios is sensitive to costs assumed for FGD. Changes in FGD costs affect overall incremental costs of reducing acid gas emissions proportionately (Table 19). For example, higher costs raise the overall cost of FGD control by just under 20% to $780 million; 20% lower costs reduce the overall cost to $530 million.

2.7 Costs to Ontario Hydro Customers

The relative attractiveness of the four scenarios from Ontario Hydro's perspective was also examined on the basis of total electricity cost. Using Environment Canada's CANSIM computer simulation model, the overall cost of electricity to Ontario consumers was predicted for each of the coal use options for the period from 1985 to 2000. The CANSIM model considers all forms of electricity generation in the Ontario Hydro system (hydro, nuclear, fossil fuels) as well as electricity imports and exports, and accounts for transmission losses in delivering electricity to customers.

The results of this analysis are presented in Table 20 and Figure 8. They indicate that by the year 2000, controlling acid gas emissions to the 215 kt/yr limit by FGD and western Canadian coal will increase the cost of electricity to Ontario consumers by approximately 8% and 16%, respectively. The Status Quo and Mixed Controls scenarios fall within this range, with electricity prices nearer those with the FGD Control scenario.

As illustrated in Figure 8, overall prices of electricity are expected to fall over the next 16 years (in constant dollar terms). This projected decline is sufficient to more than offset the price increments due to acid gas emission controls by any of the methods.

Table 20 provides a breakdown of electricity costs for different sectors of the consumer market. In the year 2000 cost increases over no control range from $373 million for control by FGD to $741 million for WCC control. These costs are almost equally split between the three major market components: manufacturing (38%), agriculture and residential (33%); and commercial, institutional and public administration (29%).

TABLE 20 COSTS OF ELECTRICITY TO ONTARIO CONSUMERS - YEAR 2000

	No Control	FGD Control	Status** Quo	Mixed Controls	WCC Control
Electricity Prices					
Avg. for Province (1985 ¢/kWh)	2.58	2.78		2.85	2.99
Increase over no control - ¢/kWh	0	0.20		0.27	0.41
(%)	(0)	(7.8)		(10.5)	(15.9)
Consumer Costs (1985 \$ x 10^6/yr)					
Manufacturing (38%)	1800	1942		1981	2082
- Increase over no control	0	142		181	282
Agriculture and Residential (33%)	1564	1687		1720	1808
- Increase over no control	0	123		156	282
Comm., Inst. & Public Admin. (29%)	1374	1482		1512	1589
- Increase over no control	0	108		138	244
Total	4738	5111		5213	5479
- Increase over no control	0	373		475	215
Average Household Cost (1985 \$/yr)	500*	539		552	579
- Increase over no control	0	39		52	79

* approximate household cost used for calculation purposes; ** not computed

The effect of electricity price increases in this range on commodity and industry prices have been predicted in an economic study for Environment Canada (Melvin, 1980). Melvin (1980) examined 103 commodities and 43 industry sectors with three different levels of pollution control. Results indicated that all commodity and industry price increases (except for electricity) would be less than 0.3% for an average national electricity price increase of 7.3%. Only nine commodities and four industries showed a price increase of more than 0.2%.

The industry analysis for Ontario, using an 8.1% electricity price increase, shows only one industrial sector (Paper and Allied Industries) with a price increase greater than 0.3%. The 0.35% price increase for this industry is thought to be biased upward because the substantial self-generation of electricity within the industry is not taken into account.

The study concludes that these price increases are, for all practical purposes, zero.

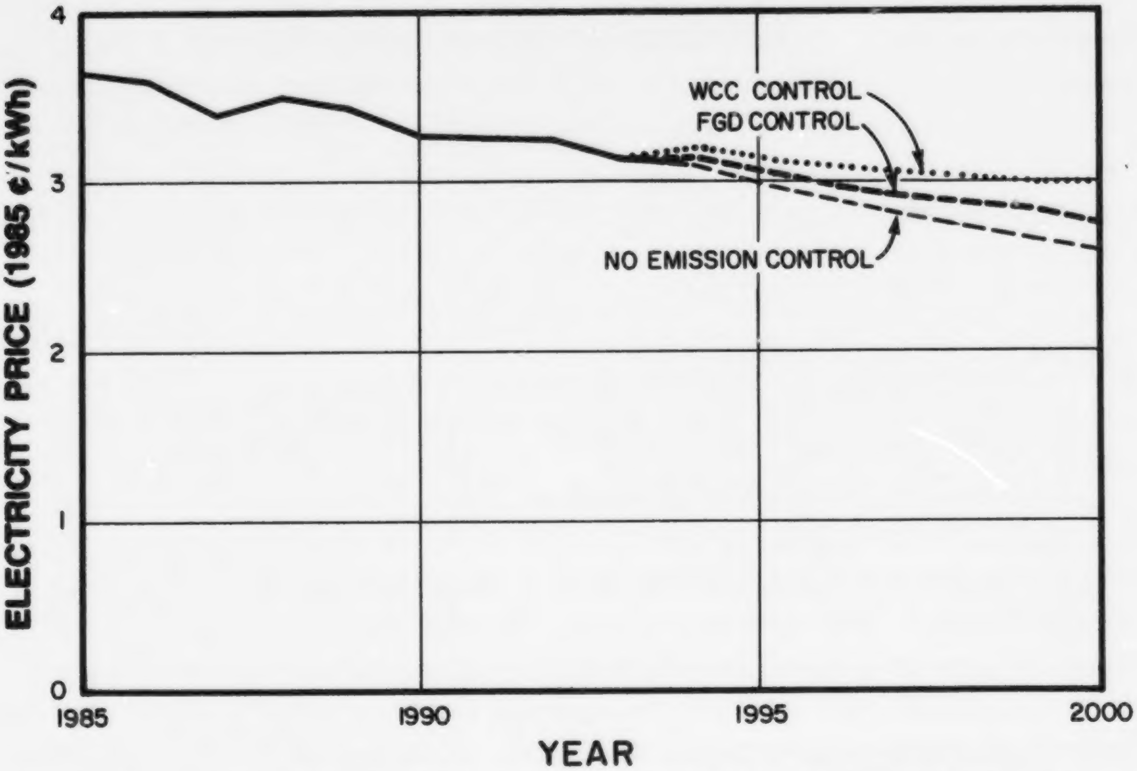

FIGURE 8 PROJECTED COSTS OF ELECTRICITY IN ONTARIO (1985 to 2000)

2.8 Costs to Canadian Society of Reducing Acid Gas Emissions (Social Costs)

2.8.1 Comparison of Costs. The comparison of costs of reducing gas emissions to Canadian society is analogous to the comparison presented from Ontario Hydro's perspective, except that it examines costs from a national perspective; that is costs incurred by society as a whole (social costs) rather than by individual companies within society. Calculation of social costs is guided by two major principles:

1) all costs incurred in the relevant jurisdiction must be taken into account; these include costs not captured in the private analysis, such as negative environmental effects and foreign exchange costs; and
2) costs are calculated on the basis of the value of the resources used.

The second principle has a number of implications. First, to capture true resource costs, private cost estimates must be adjusted for taxes, capital charges (depreciation, interest, capital cost allowance), subsidies, and profits. Although these items represent costs to a particular company, they are not, in general, resource costs to

Canadian society. For example, taxes must be paid by the company in question to the provincial and federal governments and, therefore, represent a cost to the company. From a Canadian perspective, however, the monies have simply been transferred between groups within Canada; Canadians as a whole are not worse off.

Second, all capital costs must be expensed in the year in which they occur. For example, total costs of mine expansion are included in the year in which resources are actually used. This format is consistent with Treasury Board Guidelines on benefit-cost analysis (Treasury Board, 1976).

Finally, present value calculations of social costs must be based on a social rate of discount. Consistent with the Treasury Board Guidelines, a base discount rate of 10% has been assumed and sensitivity tests for 5% and 15% undertaken.

Following these principles, several adjustments have been made to the costs of reducing acid gas emissions incurred by Ontario Hydro (Table 21). Environmental implications, which are considered in a social cost analysis, are discussed in detail in Section 4. Estimates of the resulting social costs of reducing acid gas emissions are summarized in Tables 22 to 24.

From a social perspective, capital costs of reducing acid gas emission are lower than private costs largely because a higher discount rate is used and taxes are excluded. For example, total expenditures under the FGD Control scenario are $725 million (see Table 22) compared with $996 million calculated for Ontario Hydro.

TABLE 21 MODIFICATIONS TO PRIVATE COST ESTIMATES

Cost Component	Private Costs	Social Costs
Capital Expenditures	- includes taxes - amortized and included as an annual cost	- excludes taxes - included in the year in which they occur
Operating Expenditures	- includes factors for financial charges, taxes, and profits	- includes only resource costs (materials, labour, equipment, land)
Foreign Exchange Costs	- excluded	- included
Present Value Calculations	- 6.6% private discount rate	- 10% social discount rate

TABLE 22 COMPARISON OF INCREMENTAL CAPITAL EXPENDITURES FOR REDUCING ACID GAS EMISSIONS (Social Costs) (1985 $ million, present value)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Mine	0	0	29	212
Transportation	0	0	40	158
Fuel Expenditures	**0**	**0**	**69**	**370**
Station Modifications	0	48	171	294
FGD Costs	725	616	352	0
Station Expenditures	**725**	**664**	**523**	**294**
TOTAL EXPENDITURES	**725**	**664**	**592**	**664**

Relative capital costs among the scenarios do not, however, differ significantly from the private cost perspectives; the FGD Control scenario has the highest costs, followed by the WCC Control and Status Quo scenarios ($664 million each). Capital expenditures are lowest ($592 million) for the Mixed Controls scenario.

From the perspective of Canadian society, the present value of annual costs (including capital, foreign exchange and operation and maintenance expenses) of reducing acid gas emissions through expanded use of western Canadian bituminous coal alone is 7% higher than the FGD Control option — within the margin of error for this study (Table 23). This result, which differs from Ontario Hydro's perspective, can be partially attributed to the resource cost approach. Specifically, non-resource costs (such as taxes) are excluded from the price of Canadian coal because they represent transfers between groups within Canada. For example, the price of western bituminous coal to Ontario Hydro is $90.75/t in 1985 (the resource cost is only about $72/t). When purchasing U.S. coal, taxes, profits, and some financial charges are transferred to groups outside of Canada. They are, therefore, costs which must be borne by Canadian society as a whole and form part of the social cost of U.S. coal. Consequently, incremental fuel costs under the WCC Control scenario are only $696 million (Table 23).

The attractiveness of western Canadian coal is also enhanced by the inclusion of foreign exchange costs. Foreign exchange costs are incurred when coal, supplies, equipment, or technical expertise must be purchased from another country. They

TABLE 23 COMPARISON OF TOTAL ESTIMATED COSTS TO CANADIAN SOCIETY OF REDUCING ACID GAS EMISSIONS* (1985 $ million, present value)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Incremental Fuel Costs	20	279	443	696
Station Modifications	0	48	177	307
FGD Costs	862	715	401	0
Incremental Station Costs	862	763	578	307
Incremental Foreign Exchange Costs	6	32	-51	-53
Total Costs of Reducing Emissions	888	1010	970	950
Difference from FGD Control	n/a	+14%	+9%	+7%
SO_2 and NO_x removed (kt)	1625	1861	1861	1625

* includes capital expenditures, operation and maintenance and foreign exchange costs

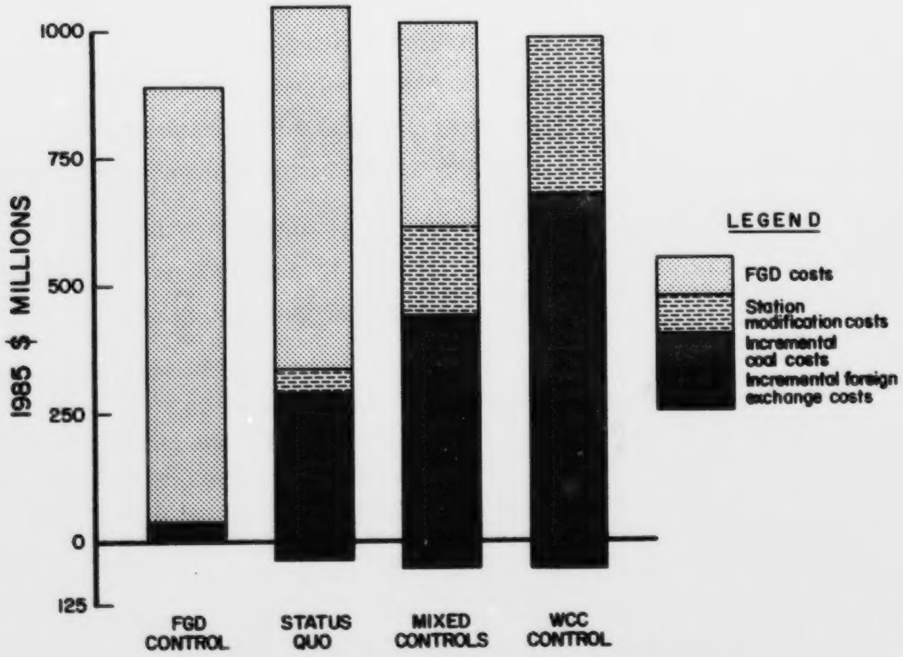

TABLE 24 ESTIMATED ANNUAL COSTS TO CANADIAN SOCIETY AND ASSOCIATED REDUCTIONS IN ACID GAS EMISSIONS

	Scenario							
	FGD Controls		Status Quo		Mixed Controls		WCC Control	
	(x 10^6 \$)*	(kt)**	(x 10^6 \$)*	(kt)**	(x 10^6 \$)*	(kt)**	(x 10^6 \$)*	(kt)**
1985	0	0	0	0	0	0	0	0
1986	0	0	7	11	7	11	0	0
1987	0	0	14	20	14	20	0	0
1988	0	0	18	30	18	30	0	0
1989	0	0	22	36	22	36	0	0
1990	0	0	24	33	24	33	0	0
1991	46	0	41	22	138	22	97	0
1992	116	0	110	17	112	17	199	0
1993	250	0	224	52	203	52	199	0
1994	292	54	296	69	216	69	196	54
1995	311	108	352	108	258	108	177	108
1996	330	175	334	175	284	175	295	175
1997	350	231	355	231	384	231	415	231
1998	384	287	474	287	446	287	531	287
1999	266	350	350	350	332	350	404	350
2000	136	420	180	420	203	420	225	420
Present Value	888	-	1010	-	970	-	950	-
Total	-	1625	-	1861	-	1861	-	1625

* includes incremental fuel costs; capital repayment and operation and maintenance for station modifications and FGD investments; and foreign exchange costs

** SO_2 and NO_x removed

represent a premium to foreign exchange savings to capture distortional effects of import duties and taxes. Foreign exchange costs are highest under the FGD Control scenario because of the high import content of FGD capital (e.g., design and technology costs) and, of course, the purchase of U.S. coal.

Finally, all capital expenditures are taken into account in total social costs in the year which they occur, rather than the portion of capital costs which are amortized over the 1985 to 2000 year period, as in the private cost analysis. Capital expenditures are higher for the FGD Control scenario; therefore, this treatment enhances the relative attractiveness of the WCC Control option.

Overall, the present value of costs of reducing acid gas emissions from the social perspective is $888 million in the FGD Control option and $950 million in the WCC Control option.

Total costs under the Status Quo scenario are $1.0 billion (14% higher than the FGD Control scenario) and about $970 million under the Mixed Controls scenario (9% higher).

In summary, results of the social cost analysis indicate that expanded use of western Canadian coal to meet emission limits may, from the perspective of Canadian society as a whole, be cost-competitive with the FGD option. The cost comparison does not take into account the flexibility of various control options. Briefly, the FGD Control scenario suggests that Ontario Hydro may undertake large investments in a technology that is unable to meet any further reductions in emission limits or that may rapidly become outdated as new technologies and acid gas control systems are developed. In the WCC Control scenario, major capital expenditures on new mine and transportation equipment are not required until the late 1990s.

2.8.2 Sensitivity Analysis. The comparison of social costs of reducing acid gas emissions is based on a number of assumptions. Some of the key assumptions correspond to those in the private cost analysis, including:

- delivered price of U.S. coal;
- delivered price of western Canadian bituminous coal;
- boiler derating; and
- FGD capital and operating costs.

Sensitivity tests, using the same variations as the sensitivity analysis on private costs were undertaken for the FGD scenario and the WCC Control scenario (Table 25). In addition, sensitivity tests were undertaken for discount rates and financial charges paid offshore.

TABLE 25 RESULTS OF SENSITIVITY TEST ON SELECTED PARAMETERS - SOCIAL COSTS (1985 $ millions, present value)

	Cost of Reducing Acid Gas Emissions	
	FGD Control Scenario	WCC Control Scenario
Task Force Assumptions	888	950
a) Variations in U.S. Coal Price		
1) coal price constant at Cdn. $69.45/t	891	789
2) Feb. 1986 exchange rate	892	769
b) Variations Western Canadian Bituminous Coal Price		
1) $80.00/t after 1989	888	928
2) $75.00/t after 1990	888	861
3) $65.00/t after 1990	888	726
c) Boiler Derating 10% more western Canadian bituminous	888	1056
d) FGD Costs		
1) 20% higher	1060	950
2) 20% lower	714	950
e) Inclusion of Interest Payments	1008	1122
f) Discount Rates		
1) 5%	1457	1580
2) 15%	558	593

Variations in the prices of U.S. and western Canadian bituminous coal, as outlined in Table 25, enhance the attractiveness of the WCC Control scenario. Higher U.S. prices reduce incremental costs of the WCC Control scenario to $769 million and $789 million, compared with FGD scenario costs of about $891 million. Lower prices for western Canadian bituminous coal reduce the cost of the WCC Control scenario; for example, at $80/t (after 1989), costs are $928 million and at $65/t (after 1990), costs fall to $726 million. These estimates should, however, be treated with caution as they assume that the distribution of price between resource costs and transfers is not affected by the price decline.

Boiler derating raises the cost of acid gas control by expanded use of the WCC Control scenario if greater coal volumes are required. As indicated in Table 25, a 10% volume increase raises the cost of the WCC Control scenario to $1.056 billion, almost 19% higher than the FGD/U.S. coal option. Under these conditions, the competitiveness of western Canadian coal control would be questionable, even from a social perspective. If additional supply costs and generating capacity replacement is added, the cost differential would widen further.

The base social cost analysis excludes all interest payments on coal mining and transportation investment and on station expenditures (FGD, ESP and boiler, coal and ash systems) on the premise that the payments would be made to other groups within Canada. As a transfer, they are not a cost to Canada as a whole. However, to the extent that investment funds are borrowed from non-Canadian sources and interest payments cannot be considered transfers, interest should be included as a social cost.

Within the scope of this study, it is not possible to reliably trace out the pattern of interest payments. To illustrate the possible impact on relative costs, all interest payments were included in a sensitivity test. As indicated under (e) in Table 25, inclusion of interest payments widens the cost differential between the FGD scenario and WCC Control scenario from 7% to 11%.

Estimates of the social costs of acid gas emission control will also depend on the discount rate used in present value calculations. Task Force assumptions used a 10% social discount rate, but in accordance with Treasury Board Guidelines, sensitivity tests were conducted for rates of 5% and 15%. A 5% discount rate raises the present value of cost of both options because expenses incurred in the future are given a greater weight; analogously, costs are lower using a 15% discount rate.

Different discount rates do not, however, significantly change the relative attractiveness of the two options (i.e., cost differences remain within the margin of error for this study).

The social costs of reducing acid gas emissions in the WCC Control scenario may be understated as the opportunity costs of coal resources not captured in royalty payments could not be calculated within the constraints of this investigation. A full analysis of this opportunity cost may increase the social cost of using western Canadian coal.

Conversely, this analysis has valued labour at prevailing market wages. To the extent that new jobs are filled by people who would otherwise be unemployed, the wage rate would exceed the economic or true resource cost of labour. Imputing a "shadow price" to reflect the differential between actual wages and this true resource cost would require forecasts of labour market conditions in the 1990s, an exercise which would introduce more error and uncertainty to the cost estimates. However, if current labour conditions prevail through the next decade, the social cost estimates presented in Tables 23 and 24 may be overestimated, especially for the WCC Control scenario.

3 EFFECTS ON EMPLOYMENT AND INCOME

The purpose of this section is to describe the socioeconomic spinoffs associated with the coal consumption and acid gas control scenarios previously presented. Greater use of western Canadian coal will increase capital investment, coal industry revenues, employment, personal income, mining industry and community stability, and transport sector revenues in western Canada. In Ontario the effect on employment and income generation of using western Canadian coal compared to the FGD Control scenario equipment is less obvious. A primary question addressed in this analysis is how levels of employment and income associated with the installation and operation of acid gas control equipment compare with those associated with growth in the coal mining, transport, and consumer goods sectors both in Ontario and across the country.

The key effects addressed are:

1. employment generated by sustained or increased western Canadian coal consumption compared to a move to U.S. high-sulphur coal and emissions control systems;
2. growth in Gross Domestic Product (GDP) and interregional trade generated by increased western Canadian coal consumption; and
3. coal industry and mining community stability resulting from increased western Canadian coal consumption.

Since regional perspectives are important, provincial accounts are used in the analysis. All analyses are based on cost data which were presented in Section 2.

3.1 Methodology

Analyses of the economic impact of increased western Canadian coal consumption have been prepared for the FGD Control, Status Quo, Mixed Controls, and Western Canadian Coal (WCC) Control scenarios. These effects are measured in terms of changes in employment and gross domestic product (GDP at market price) relative to the FGD Control scenario. Employment is measured in person-years of full-time employment and converted to job equivalents where appropriate. At market price, GDP is a measure of the total value of outputs of goods and services produced for scenario-dependent activities over a given period of time. Since market prices are used, taxes and subsidies are included in the measure of production. The term "domestic" refers to the inclusion of only those goods and services produced in Canada.

Estimates of the GDP and employment effects are derived at three levels: direct, indirect, and induced.

1) Direct effects are the employment and GDP impact resulting directly from the construction and operation of the mines, transportation facilities, combustion, coal handling, and emissions facilities. For example, direct employment includes jobs at the mines, along the railway, at the Thunder Bay terminal, on the lakers, and at the Ontario Hydro sites.

2) The indirect (supply-related) effects are employment and GDP resulting from purchases by the coal mining companies, transportation companies, and Ontario Hydro. In this study, first and second order indirect effects are estimated. Examples of first order indirect employment are jobs at manufacturing firms that supply mining equipment and railroad rolling stock to the railway companies.
Second order indirect employment is generated, for example, by the supply of goods and services used in the manufacture of mining equipment and railroad rolling stock.

3) Induced effects are the jobs and GDP generated by consumer spending of workers with the mining and transportation companies, Ontario Hydro, and the manufacturing and other companies that supply materials, equipment and services to these groups. Induced effects are calculated by applying regional multipliers to direct and indirect salaries and wages.

A graphic representation of the impact analysis organization is presented in Figure 9. The following steps are involved in estimating GDP and employment:

1) Based on the coal consumption scenarios, capital and operations expenditures are determined for each component of the coal cycle annually over the study period, 1985 to 2000.

2) The expenditures are then distributed as income to industrial sectors defined by Statistics Canada Standard Industrial Classes. Broadly defined expenditures require some disaggregation.

3) GDP effects are calculated from these income streams as:

$$V_i = A_i \times I_i$$

$$GDP = \Sigma_i V_i$$

where: i denotes the industry category

V_i = value-added

A_i = ratio of value-added to total income*

I_i = total income (attributed to expenditures in industry "i")

GDP = sum of value-added

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* Ratios of value-added to total income and of wages and salaries to value-added are derived from the Corporation Financial Statistics, 1982 (Statistics Canada, Cat. No. 61-207). Average wages are derived from Employment Earning and Hours, Nov. 1984, Statistics Canada Cat. No. 72-002. Average wages were updated to 1985 values and adjusted for employer-paid benefits. Estimated ratios and parameter values are presented in Appendix C.

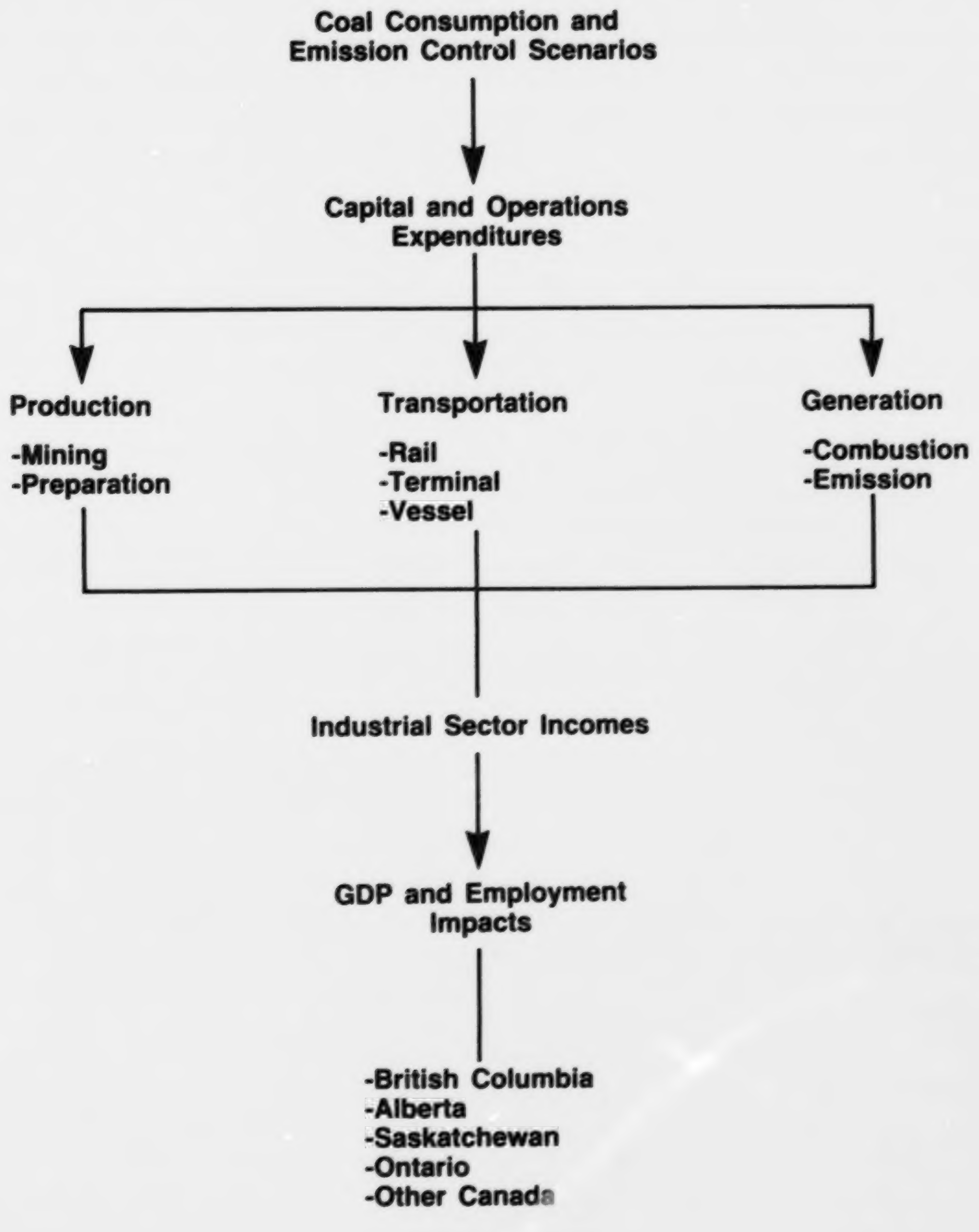

FIGURE 9 ORGANIZATION OF THE IMPACT ANALYSIS

4) Employment effects are calculated from GDP flows as:

$$W_i = b_i \times V_i$$

$$E_i = W_i / s_i$$

$$E = \Sigma_i E_i$$

where: W_i = total wages and salaries

b_i = ratio of wages and salaries to value-added*

E_i = direct employment generated by income received by industry "i"

s_i = average wage/salary in industry "i"

E = sum of employment across industries

5) Indirect GDP and employment effects are estimated in an analogous method, with ratios applied to income received by first and second order suppliers. Industry and province specific factors (or weighted averages) are used where possible; otherwise, generalized ratios and average Canadian wages are applied.

6) Direct and indirect effects are distributed by province based on:

- information obtained from key industry informants;
- consultants' and Task Force members' knowledge of materials and equipment production and supply capabilities in Canada; and
- corroboration with Statistics Canada's Input-Ouput Model interprovincial supply factors.

7) Induced employment and GDP are estimated by province using province-specific multipliers from the 1979 Statistics Canada Interprovincial Input-Ouput Model.

The expenditure categories and resulting income flows measured in this analysis are itemized in Table 26. The expenditure categories encompass all elements of change associated with the scenarios. For this analysis, net effects are defined as the differences (at one time or cumulatively over time) between the FGD Control scenario and other scenarios.

The above methodology does not adjust for employment substitution effects. That is to say, all employment generation is assumed to be a net incremental addition to the economy, with no adjustment for the possible removal or draw on labour resources in

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* Ratios of value-added to total income and of wages and salaries to value-added are derived from the Corporation Financial Statistics, 1982 (Statistics Canada, Cat. No. 61-207). Average wages are derived from Employment Earning and Hours, Nov. 1984, Statistics Canada Cat. No. 72-002. Average wages were updated to 1985 values and adjusted for employer-paid benefits. Estimated ratios and parameter values are presented in Appendix C.

TABLE 26 FINANCIAL FLOWS MEASURED

	Estimates of GDP and Employment Based on Income Arising From:	
	Capital Expenditures	Operations Expenditures/ Income
Production		
• mining and preparation	• mine development	• coal sales
Transportation		
• rail	• train set purchases	• rail transport charges
• terminal	• terminal expansion	• terminal transport charges
• vessel	• ship building	• water transport charges
Generation		
• combustion	• modification to boilers and materials handling	• incremental power plant operating costs
• emissions	• modifications to or replacement of electrostatic precipitators (ESP)	• incremental power plant operating costs
	• purchase and installation of flue gas desulphurization units (FGD)	• incremental power plant operating costs

other sectors of the economy. To the extent that such substitution occurs, the estimates derived in this analysis will overestimate the net impact on employment.

The methodology also does not account for rounds of indirect employment generation beyond second order effects. The calculations of indirect employment derived in this analysis will, therefore, tend to underestimate true indirect employment by a relatively constant factor across each scenario.

The methodology adopted is based on principles of static input-output analysis. It, therefore, does not incorporate any supply constraints or supply-demand effects as would a dynamic simulation model.

The estimates of employment and GDP derived in this analysis are precise enough for overview policy analysis, but should be refined to explicitly incorporate the influences discussed before being used in management decisions.

3.2 Mining and Preparation

Total production of western Canadian coal for the Ontario utility market under the study scenarios varies from 28.1 x 10^6 t (FGD Control) to 83.5 x 10^6 t (Western

Canadian Coal Control) over the 1985 to 2000 year period. Compared with production under Status Quo conditions these values represent the extremes of a reduction of 25.7×10^6 t or a gain of 29.7×10^6 t. Estimated capital expenditures of $212 million (discounted) are required to expand coal production capacity to accommodate maximum sales of bituminous coal assumed (i.e., under the Western Canadian Coal Control scenario).

The projected employment and GDP effects associated with the study scenarios for coal mining and preparation are summarized in Table 27.

TABLE 27 CUMULATIVE GDP AND EMPLOYMENT DATA - COAL MINING AND PREPARATION (1985 to 2000)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Income (GDP)				
Total GDP (1985 $ millions)*	564.2	1033.3	1281.4	1454.9
Impact Relative to FGD Control		469.1	717.2	890.7
Distribution of Effects:				
B.C.		134.5	204.3	249.6
Alta.		253.9	385.5	468.7
Sask.		3.7	5.7	7.0
Ont.		49.5	80.3	113.9
Other Canada		27.5	41.4	51.6
Employment				
Total Employment ($\times 10^3$ person-years)**	13.9	33.1	48.2	70.8
Impact Relative to FGD Control		19.2	34.3	56.9
Distribution of Effects:				
B.C.		5.3	9.3	15.2
Alta.		9.1	16.1	26.0
Sask.		0.2	0.2	0.4
Ont.		3.1	5.7	10.6
Other Canada		1.6	3.0	4.7

* present value using 10% discount rate

** direct, indirect, and induced

The Status Quo scenario represents a GDP gain; $469 million (discounted) over the study period relative to the FGD scenario. The Mixed Controls and WCC Control scenarios are similar in their GDP effects (contributions of $717 to $891 million) partly due to the concentration of production and investment late in the study period under the WCC Control option.

Figure 10 illustrates the number of jobs (direct, indirect, and induced) related to mining and preparation at benchmark dates in the study period. In general, employment tracks the coal production and consumption scenarios. Employment differences prior to the year 2000 are in the order of 1000 to 3000 jobs, a notable exception is that the WCC Control scenario generates more than 13 000 jobs in the year 2000 (6500 direct and indirect, 6500 induced). This compares with total average employment (all industries) in Canada of 11 000 000 in 1984.

Figure 10 also illustrates how employment may change from maintenance of current levels, as denoted by the Status Quo scenario. For example, in the year 2000,

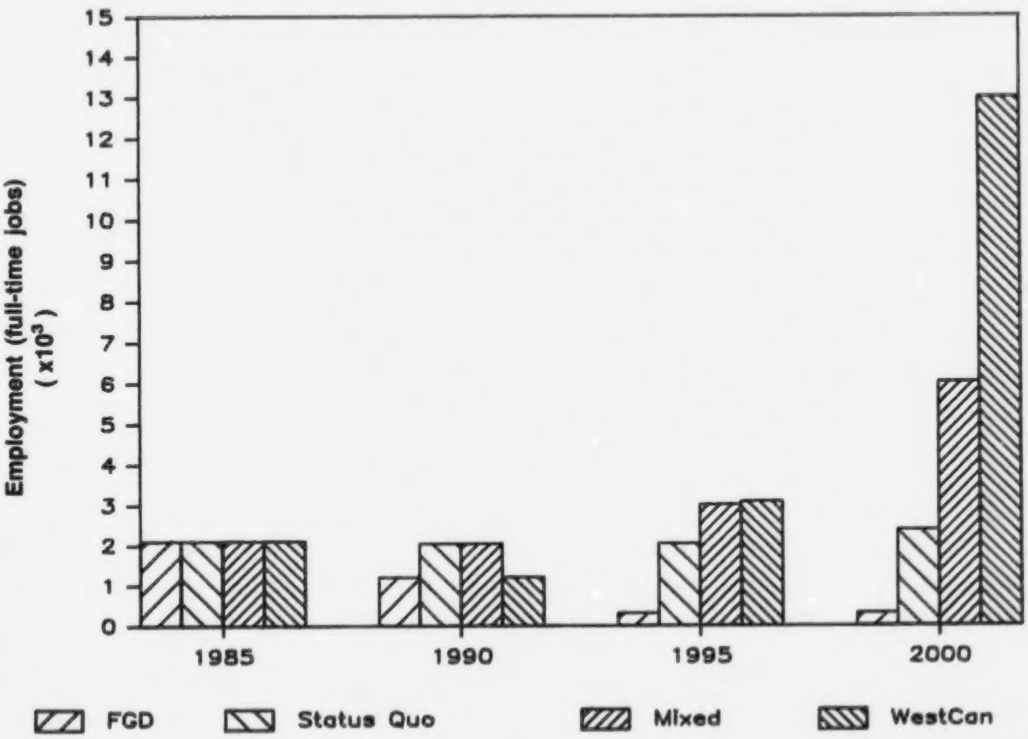


FIGURE 10 ANNUAL EMPLOYMENT RELATED TO MINING AND PREPARATION - Canada Total

FGD control results in a loss in mining and preparation employment compared with a significant gain under the WCC Control option.

The expansion or contraction of western Canada coal production has employment and income effects on eastern Canada as well as western Canada. The distributions of cumulative GDP and employment by province are illustrated in Figures 11 and 12. As might be expected, GDP and employment effects are concentrated in Alberta and British Columbia in proportion to the assumed allocation of bituminous coal production (66% Alberta, 34% B.C.). However, Ontario also benefits from increased coal mining and preparation activity in western Canada through purchases of capital and operating equipment and consumer purchases of goods and services produced in Ontario.

Capital expenditures contribute about 12% of cumulative employment under the WCC Control scenario and about 3% in the Mixed Controls scenario; in all other scenarios, capital expenditures have no effect on employment (or income) generation.

3.3 Transportation

Employment and GDP will be generated by the provision of rail, terminal, and laker vessel services, by the manufacture of rolling stock and locomotives, by the manufacture of self-unloading vessels, and by the construction of the terminal expansion.

Since transportation charges account for over half the delivered cost of western Canadian coal, it is not surprising that the employment and GDP impacts related to transportation are large. The key effect data relating to coal transportation under the study scenarios are summarized in Table 28.

Underlying the data is the predominance of rail charges and the sizeable capital investments incurred under the WCC Control scenario for train set and vessel manufacture. It is assumed that two-thirds of train set expenditures go to Ontario manufacturers and one-third to other parts of Canada (e.g., Quebec). It is also assumed that 40% of vessel expenditures would accrue to Ontario manufacturers and 60% to other parts of Canada (e.g., Quebec).

Figure 13 presents the cumulative GDP generated by the study scenarios over the 1985 to 2000 year period. Nearly 50% of transportation-related GDP accrues to Ontario in the form of rail, terminal, and vessel operating revenue, capital equipment purchases, and consumer expenditures. The data indicate that moving from the FGD Control to the Status Quo scenario results in a gain of $606 million (i.e., moving away from current coal levels towards the FGD Control option results in a GDP loss of $606 million). About $278 million of the gain occurs in Ontario. The latter figure (recognizing

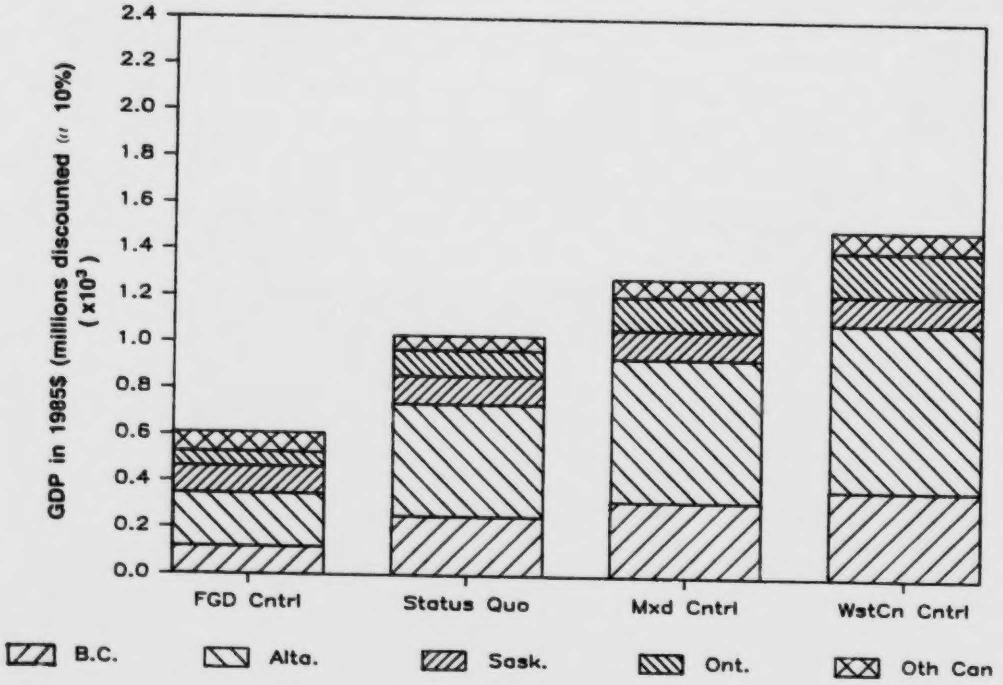


FIGURE 11 CUMULATIVE GDP 1985 to 2000 (Coal Mining and Preparation - Canada Total)

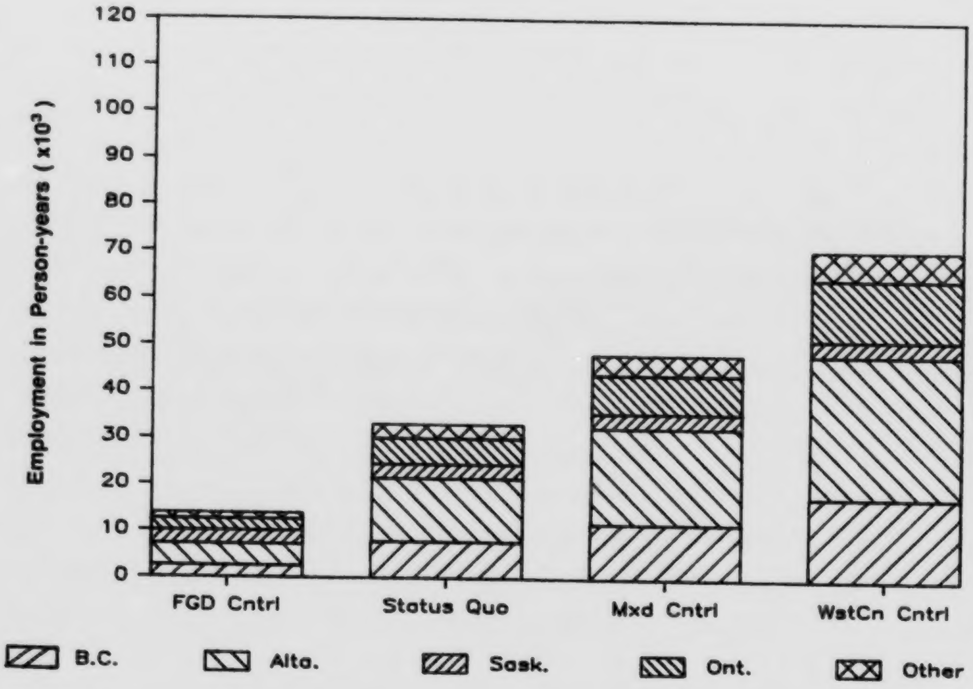


FIGURE 12 CUMULATIVE EMPLOYMENT 1985 to 2000 (Coal Mining and Preparation - Canada Total)

TABLE 28 CUMULATIVE GDP AND EMPLOYMENT DATA - TRANSPORTATION (1985-2000)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Income (GDP)				
Total GDP (1985 $ millions)*	1002.2	1607.7	1984.8	2207.0
Impact Relative to FGD Control		605.5	982.6	1204.8
Distribution of Effects:				
B.C.		115.2	117.0	188.9
Alta.		117.7	181.7	197.1
Sask.		3.6	6.1	7.4
Ont.		277.9	458.8	573.0
Other Canada		90.6	159.0	238.4
Employment				
Total Employment (x 10^3 person-years)	31.1	61.1	87.5	115.0
Impact Relative to FGD Control		30.0	56.4	83.9
Distribution of Effects:				
B.C.		5.7	10.0	13.4
Alta.		5.4	9.5	12.7
Sask.		0.1	0.3	0.4
Ont.		13.8	26.3	39.8
Other Canada		5.0	10.3	17.6

* present value using 10% discount rate
** direct, indirect, and induced

it is a cumulative figure discounted over sixteen years) compares with a 1983 total GDP in Ontario of $151 650 million (1983$).

Similarly, moving from the FGD Control to the Mixed Controls or WCC Control scenarios results in a maximum cumulative GDP increase in western Canada of between $365 million and $395 million (discounted). Despite the 17% greater coal volumes of the WCC Control scenario, discounting results in only 8% greater GDP generated in western Canada under the WCC Control scenario than under the Mixed Controls scenario.

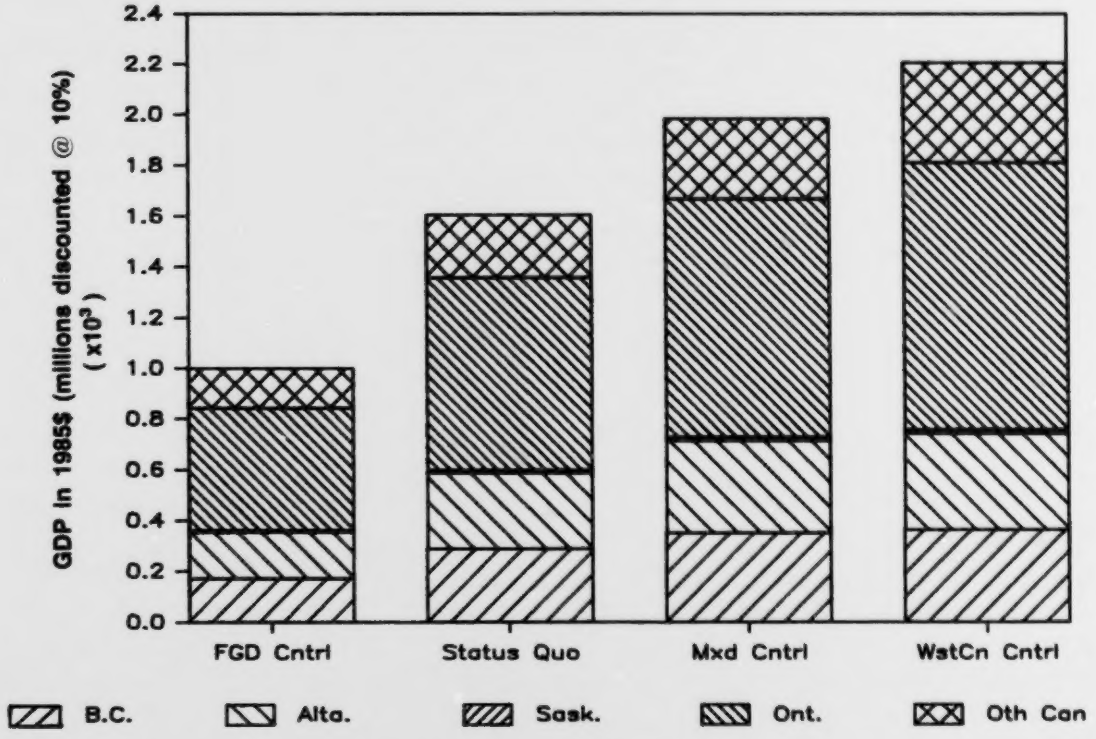


FIGURE 13 CUMULATIVE GDP 1985 to 2000 (Transportation - Canada Total)

Figure 14 illustrates cumulative employment related to transportation. As with GDP, Ontario accounts for nearly one-half of the employment generated by coal transport through the prairie rail/Great Lakes system.

Figure 15 shows the number of jobs (direct, indirect and induced) associated with western Canadian coal transportation at benchmark dates in the study period. In general, the difference in employment between scenarios increases with time. By 1995, the difference in employment between scenarios reaches 6000 jobs. By the year 2000 under the WCC Control scenario, nearly 20 000 jobs are created (11 000 direct and indirect, 9000 induced). In the same year, the FGD Control scenario results in less than 1000 jobs, some 3500 jobs less than under the Status Quo scenario and 19 000 jobs less than under the WCC Control scenario.

3.4 Station Modifications and Emission Control Equipment

The key impact data for the combustion and emissions component of the coal cycle are summarized in Table 29. The key factors underlying effects in this sector are:

- the concentration of capital and operations expenditures in the Province of Ontario;

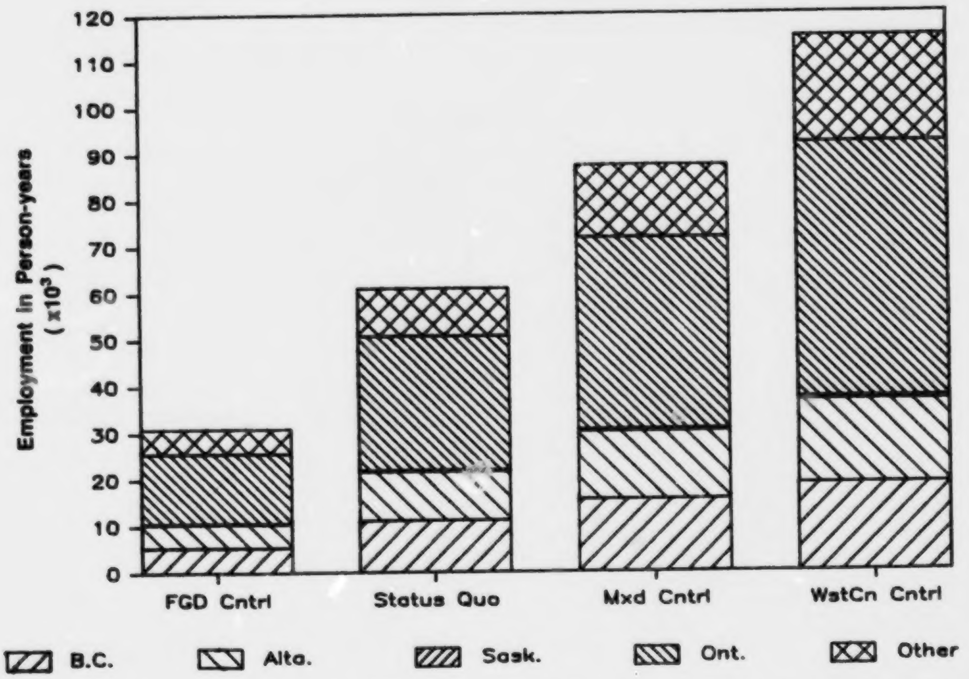


FIGURE 14 CUMULATIVE EMPLOYMENT 1985 to 2000 (Transportation - Canada Total)

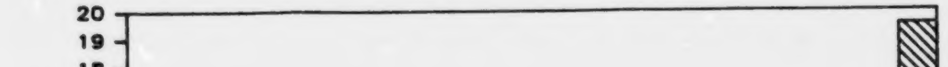


FIGURE 15 ANNUAL EMPLOYMENT (Transportation - Canada Total)

TABLE 29 CUMULATIVE GDP AND EMPLOYMENT DATA - STATION MODIFICATIONS AND EMISSION CONTROL EQUIPMENT (1985 to 2000)

	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Income (GDP)				
Total GDP (1985 $ millions)*	808.2	701.8	565.9	353.3
Impact Relative to FGD Control		(106.4)	(242.3)	(454.9)
Distribution of Effects:				
B.C.		(1.0)	(2.5)	(4.8)
Alta.		(3.1)	(7.3)	(13.7)
Sask.		(0.7)	(1.6)	(3.2)
Ont.		(93.6)	(212.4)	(398.5)
Other Canada		(7.9)	(18.5)	(34.7)
Employment				
Total Employment (x 10^3 person-years)**	59.0	52.5	39.5	18.9
Impact Relative to FGD Control		(6.5)	(19.5)	(40.1)
Distribution to Effects:				
B.C.		(0.0)	(0.2)	(0.3)
Alta.		(0.1)	(0.1)	(0.5)
Sask.		(0.0)	(0.0)	(0.1)
Ont.		(5.9)	(17.7)	(36.4)
Other Canada		(0.5)	(1.5)	(2.8)

* present value using 10% discount rate
** direct, indirect, and induced
( ) denotes decrease from FGD Control

- the clear tradeoffs between scenarios in both the type (i.e., station modifications versus emissions control) and extent of expenditures.

Relative to the FGD Control scenario, use of western coal results in smaller contributions to Canadian GDP at the generating stations. This result reflects lower station capital and operating costs associated with increased use of western Canadian coal; under the FGD Control scenario (relatively costly) manufacture, installation, and operation of FGD equipment generates considerable employment and income. Under the Mixed Controls scenario, effects arise from both FGD investments and station modifications at Nanticoke, with overall effects similar to the FGD Control scenario. The Status Quo and WCC Control scenarios result in $106 million and $455 million less in GDP at the station than the FGD Control scenario.

As illustrated in Figures 16 and 17, cumulative GDP and employment effects are concentrated in Ontario. Figure 18 highlights the relative employment generation across scenarios for benchmark years. The late emerging importance of capital expenditures for station modifications and emission equipment is illustrated by the large effects shown in 1995. Operation and maintenance in the year 2000 of a full complement of FGD units yield considerably greater employment spin-offs (i.e., under FGD Control, Status Quo and Mixed Controls scenarios) than incremental station requirements under the WCC option.

In contrast to the mining and preparation and transportation components of the coal cycle, employment and income effects at the station are attributed almost entirely to capital expenditures; incremental operating and maintenance costs are small.

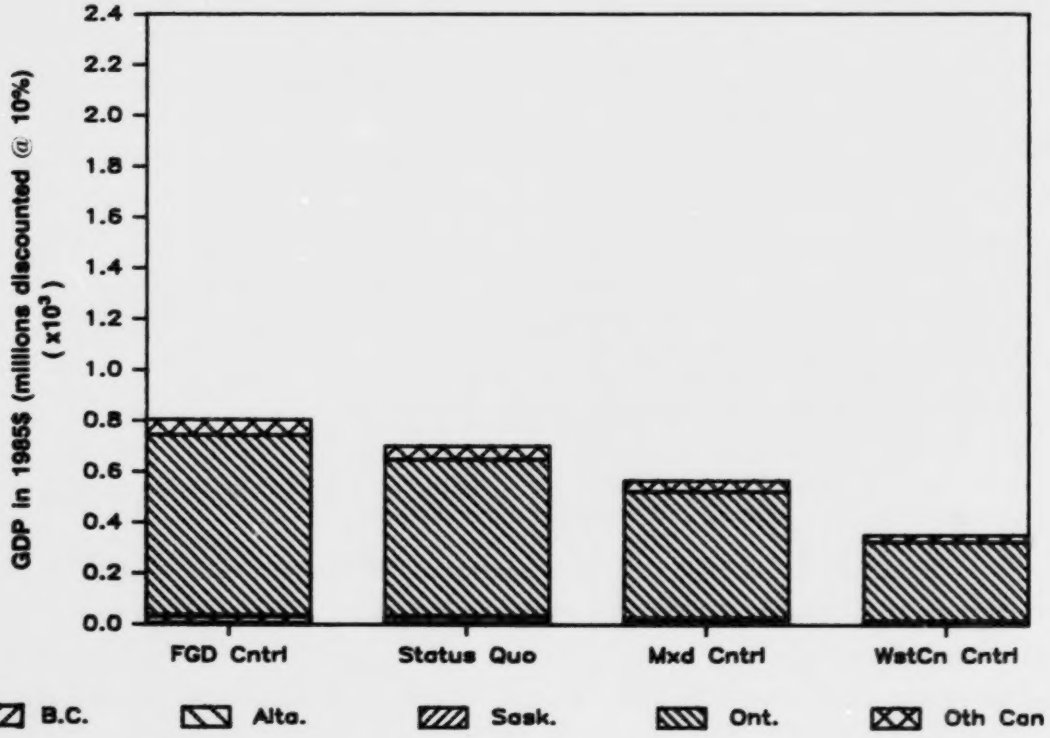


FIGURE 16 CUMULATIVE GDP 1985 to 2000 (Combustion/Emission - Canada Total)

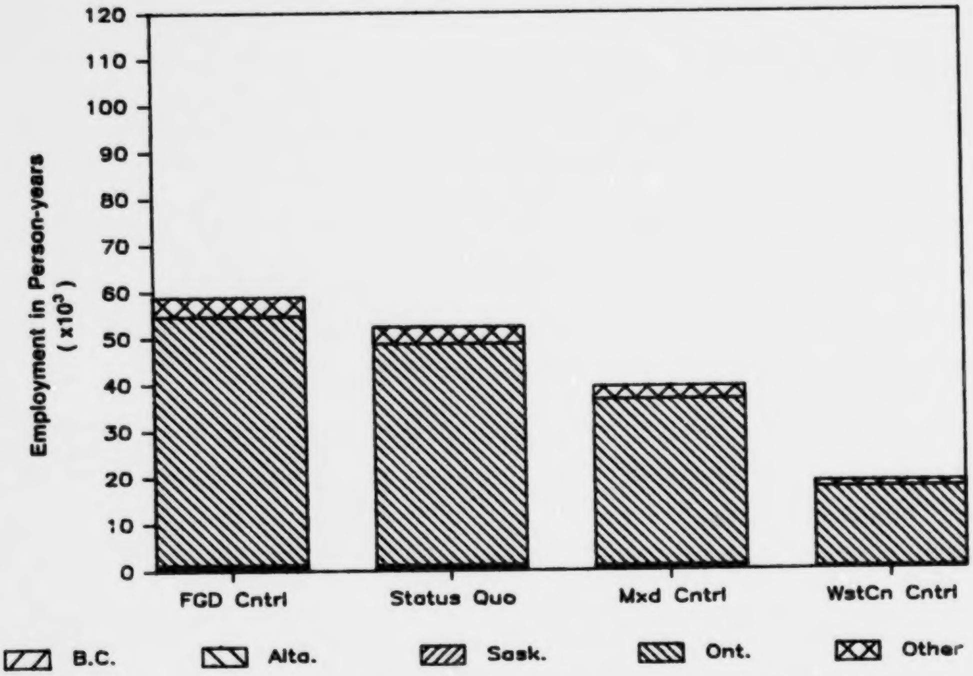


FIGURE 17 CUMULATIVE EMPLOYMENT 1985 to 2000 (Combustion/ Emissions - Canada Total)

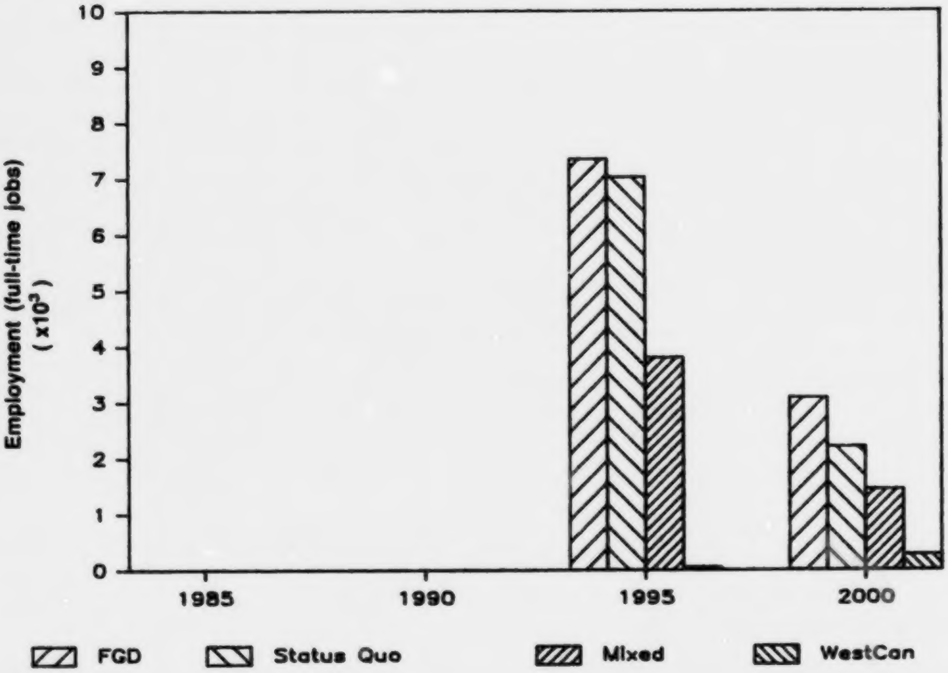


FIGURE 18 ANNUAL EMPLOYMENT (Combustion and Emissions - Canada Total)

3.5 Summary of Effects

3.5.1 Employment. In consolidating the employment impact data it is important to recognize the two essential and related tradeoffs under consideration:

1) the substitution of coal production and transportation related income and employment for acid gas emission control; and

2) the exchange of Ontario-based activity (plant modifications to control acid gases) for western Canadian-based coal production.

Table 30 presents detailed cumulative employment data by coal cycle component, by province, and by capital expenditures versus operations. Figures 19 and 20 provide graphical representations of these splits.

Highlights of the employment impact data are:

- Employment creation is greatest under the Western Canadian Coal Control scenario; 205 000 person-years between 1985 and 2000 compared with 175 000 and 147 000 under the Mixed Controls and Status Quo scenarios. The FGD Control scenario yields the lowest overall level of employment generation; 104 000 person-years or 52% of the WCC Control scenario (Table 30).
- Ontario accounts for 41% to 68% of total employment generated under all the scenarios (Figure 20).
- Relative to all other scenarios, the FGD Control scenario results in lower levels of employment in all jurisdictions. Differences range from 38 000 person-years in Alberta (compared to the WCC Control scenario) to 252 person-years in Saskatchewan (compared to the Status Quo scenario). In other words, employment generated by the installation and operation of FGD does not offset potential direct, indirect, and induced effects associated with maintained or expanded use of western Canadian coal. Even in Ontario, the FGD Control scenario generates 11 000 fewer person-years than the Status Quo and 14 000 fewer than the WCC Control scenarios (Table 30).
- Relative to the Status Quo, the Mixed Controls scenario results in gains in employment in all jurisdictions. Given constant sales of lignite coal from Saskatchewan, effects on this province are relatively small and primarily due to direct transportation and induced effects. In Alberta and B.C., combined employment would likely expand by some 19 000 person-years, accompanied by an expansion (of 3400 person-years) in Ontario. The gains in Ontario reflect direct, indirect, and induced effects of expanded use of western Canadian coal and installation of FGD (Table 30).
- Relative to the Status Quo, the WCC Control scenario results in significant gains in all provinces except Ontario where station combustion and coal supply modification employment gains are not sufficient to offset the reduced FGD-related employment in the Status Quo scenario (Table 30).
- In all scenarios, employment generated in "other parts of Canada" is slightly less than the employment generated in either B.C. or Alberta. This employment is

TABLE 30 SUMMARY OF EMPLOYMENT EFFECTS (1985 to 2000) (cumulative person-years)

Scenario	Production		Transportation				Generation					Change Relative to FGD Control
	Mine		Rail		Terminal/Vessel		Combustion		Emission*			
	Cap.	Opn.	Cap.	Opn.	Cap.	Opn.	Cap.	Opn.	Cap.	Opn.	Total	
FGD Control												
B.C.	0	2 559	0	5 367	0	47	0	0	383	103	8 459	
Alta.	0	4 583	0	5 065	0	66	0	0	548	148	10 410	
Sask.	0	2 907	0	140	0	20	0	0	164	44	3 275	
Ontario	0	2 515	0	10 221	0	4 784	0	0	42 166	11 260	70 946	
Other Canada	0	1 375	0	4 943	0	399	0	0	3 286	886	10 889	
Total	0	13 939	0	25 736	0	5 316	0	0	46 547	12 441	103 979	
Status Quo												
B.C.	0	7 810	0	10 995	0	111	4	0	368	61	19 349	10 890
Alta.	0	13 598	0	10 331	0	159	5	0	526	87	24 706	14 296
Sask.	0	3 045	0	248	0	48	2	0	158	26	3 527	252
Ontario	0	5 568	0	17 769	0	11 057	387	19	40 466	6 645	81 911	10 965
Other Canada	0	3 048	0	9 392	0	953	31	1	3 156	523	17 104	6 215
Total	0	33 069	0	48 735	0	12 328	429	20	44 674	7 342	146 597	42 618
Mixed Controls												
B.C.	406	11 476	23	15 310	0	149	12	2	279	34	27 691	19 232
Alta.	714	19 894	36	14 385	0	213	17	3	399	48	35 709	25 299
Sask.	11	3 142	10	346	0	64	5	1	120	14	3 713	438
Ontario	589	7 701	1 625	24 742	269	14 628	1 273	222	30 585	3 673	85 307	14 361
Other Canada	125	4 217	910	13 078	403	1 276	101	17	2 395	289	22 811	11 922
Total	1 845	46 430	2 604	67 861	672	16 330	1 480	245	33 778	4 058	175 231	71 252
WCC Control												
B.C.	2 573	15 163	52	18 521	63	187	25	5	124	5	36 718	28 259
Alta.	4 380	26 224	79	17 402	99	270	35	7	177	8	48 681	38 271
Sask.	64	3 240	22	418	27	81	11	2	53	2	3 920	645
Ontario	3 228	9 844	3 613	29 933	3 265	18 054	2 675	506	13 371	580	85 069	14 123
Other Canada	737	5 393	2 023	15 821	3 492	1 619	212	40	1 062	46	30 445	19 556
Total	10 982	59 864	5 789	82 095	6 946	20 211	2 958	560	14 787	641	204 833	100 854

* includes modifications to electrostatic precipitators

largely attributed to transportation activity and induced employment from all stages of the coal cycle.

- Operations account for most of the employment generated by mining and preparation and transportation activities. At the station, employment activities are largely attributable to capital expenditures. This pattern is consistent among the scenarios (Figure 19).

The estimates of total Canadian employment, and the GDP figures presented in Table 31 must be interpreted as maximum values. They are gross estimates because they do not take into account the degree to which employment represents substitution of existing employed workers and the degree to which new jobs are filled by the unemployed.

Furthermore, gross estimates do not consider employment generated in alternative investment opportunities. As previously discussed (present value) cumulative private costs of meeting emission limits is $654 million under the FGD Control scenario and $1.280 billion under the WCC Control scenario. The cost difference ($626 million) could be invested elsewhere in Canada, with associated employment and income generated. Following this argument, differences in net employment and income created under the two scenarios would be relatively small, arising only from differences in labour:capital ratios of the various types of investment projects.

There is, however, an important caveat to this argument. Under the FGD Control scenario, a greater portion of the total expenditures would flow outside the country for purchase of U.S. coal. Under the WCC Control scenario, funds are spent in Canada, generating employment and income which otherwise would be enjoyed by American mining and transport companies. Transferring expenditures on U.S. coal to Canadian sources would, by rough estimation, generate an incremental 63 000 person-years of employment. This figure can be considered a minimum estimate of net employment effects associated with the WCC Control scenario over the FGD scenario. The possible range of employment effects, therefore, is 63 000 to 101 000 person-years of employment over the 1985 to 2000 year period.

3.5.2 Gross Domestic Product (GDP) Generation. Detailed cumulative GDP data by coal cycle component, by province, and by capital expenditures versus operations are presented in Table 31. All time streams of GDP have been discounted at 10%/yr to provide present value totals; therefore, the timing of capital and operating expenditures influences the results.

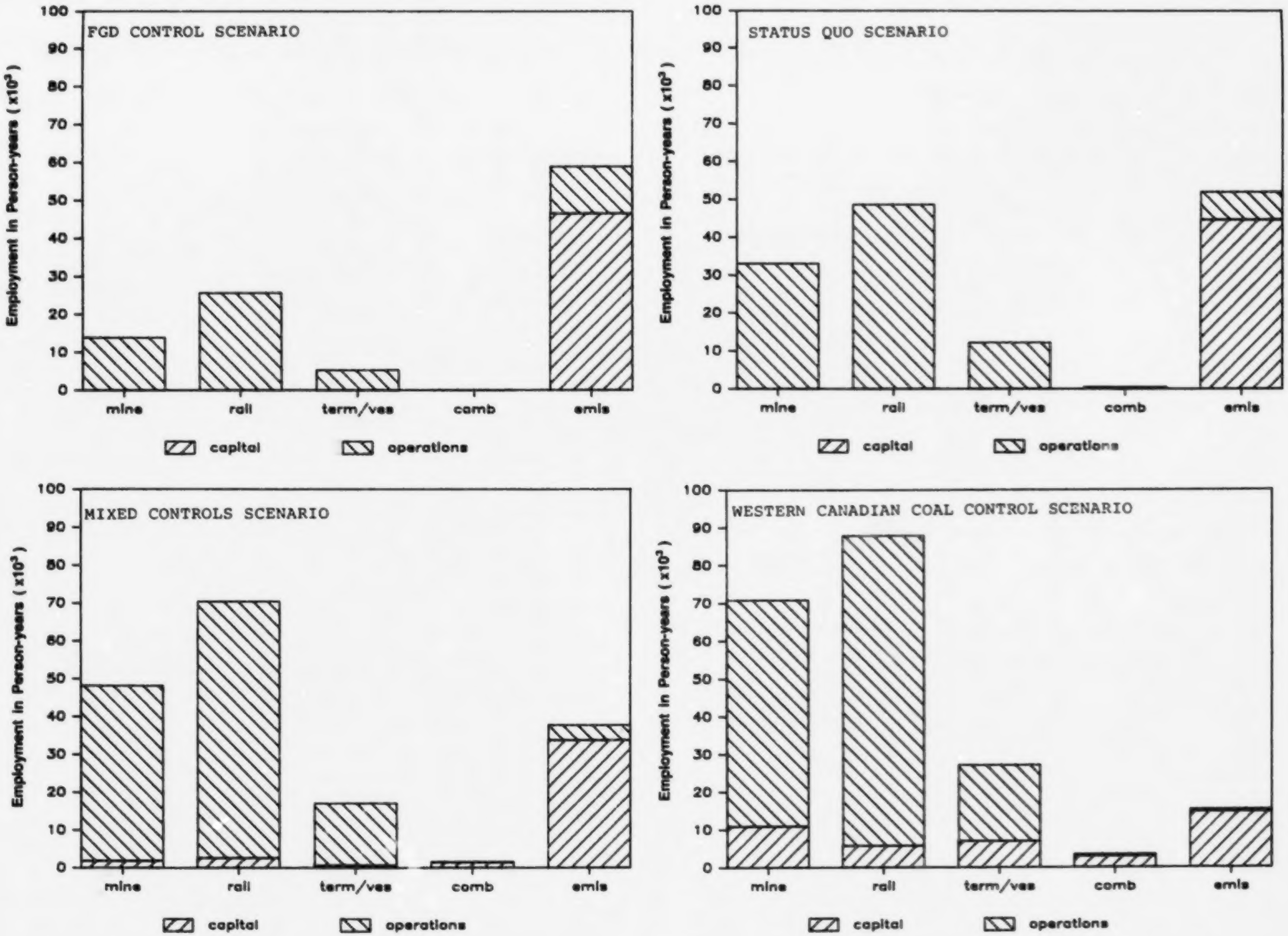


FIGURE 19 CUMULATIVE EMPLOYMENT BY SCENARIO AND SOURCE (1985 to 2000) (Canada Total by Coal Cycle)

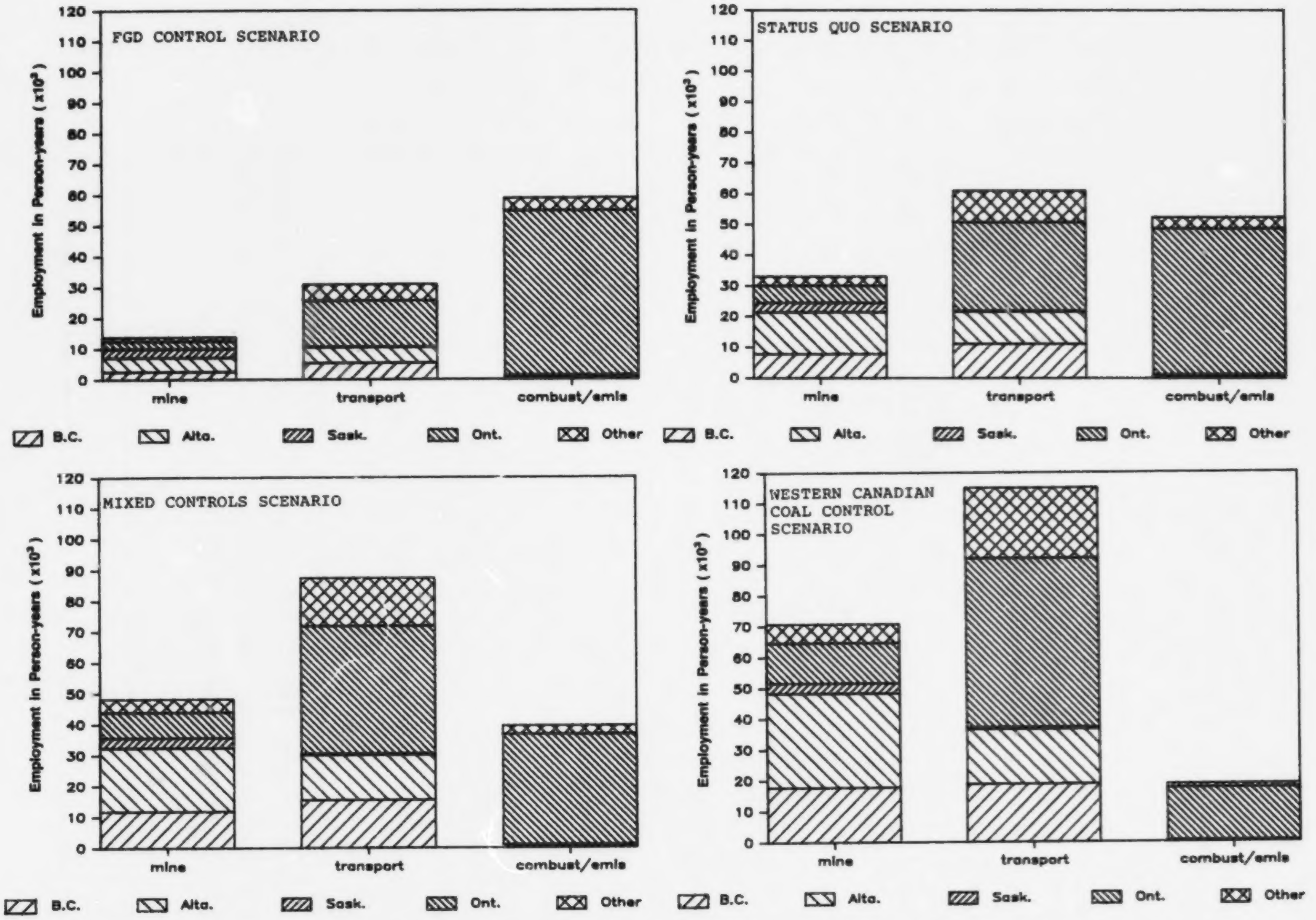


FIGURE 20 CUMULATIVE EMPLOYMENT BY SCENARIO AND PROVINCE (1985 to 2000) (Canada Total by Province)

TABLE 31 SUMMARY OF GDP EFFECTS (1985 to 2000) (1985 $ millions, discounted at 10%)

Scenario	Production		Transportation				Generation					Change Relative to FGD Control
	Mine		Rail		Terminal/Vessel		Combustions		Emissions			
	Cap.	Opn.	Cap.	Opn.	Cap.	Opn.	Cap.	Opn.	Cap.	Opn.	Total	
FGD Control												
B.C.	0.0	119.1	0.0	171.6	0.0	1.6	0.0	0.0	7.1	1.5	300.9	
Alta.	0.0	229.8	0.0	177.8	0.0	4.5	0.0	0.0	20.1	4.2	436.4	
Sask.	0.0	116.4	0.0	6.3	0.0	1.0	0.0	0.0	4.5	1.0	129.2	
Ontario	0.0	62.6	0.0	307.9	0.0	173.6	0.0	0.0	581.5	126.7	1252.3	
Other Canada	0.0	83.1	0.0	146.6	0.0	11.3	0.0	0.0	50.9	10.7	302.6	
Total	0.0	611.0	0.0	810.2	0.0	192.0	0.0	0.0	664.1	144.1	2421.4	
Status Quo												
B.C.	0.0	253.6	0.0	286.0	0.0	2.9	0.1	0.0	6.6	0.9	550.1	249.2
Alta.	0.0	483.7	0.0	291.7	0.0	8.3	0.3	0.0	18.5	2.4	804.9	368.5
Sask.	0.0	120.1	0.0	9.0	0.0	1.9	0.1	0.0	4.2	0.5	135.8	6.6
Ontario	0.0	112.1	0.0	441.8	0.0	317.6	7.0	0.0	535.5	72.0	1486.0	233.7
Other Canada	0.0	63.8	0.0	227.6	0.0	20.9	0.8	0.0	46.8	6.1	366.0	63.4
Total	0.0	1033.3	0.0	1256.1	0.0	351.6	8.3	0.0	611.6	81.9	3342.8	921.4
Mixed Control												
B.C.	5.7	318.0	0.4	346.3	0.0	3.5	0.3	0.0	5.3	0.5	680.0	379.1
Alta.	10.4	605.3	1.1	353.1	0.0	9.8	0.8	0.1	14.8	1.3	996.7	560.3
Sask.	0.2	121.9	0.3	10.9	0.0	2.2	0.2	0.0	3.4	0.3	139.4	10.2
Ontario	7.7	135.5	30.8	534.9	0.0	374.6	24.5	2.4	430.6	38.3	1579.3	327.0
Other Canada	1.5	76.3	16.6	275.5	0.0	24.8	2.1	0.2	37.6	3.2	437.8	135.2
Total	25.5	1257.0	49.2	1520.7	0.0	414.9	27.9	2.7	491.7	43.6	3833.2	1411.8
WCC Control												
B.C.	37.4	341.9	0.8	356.8	0.9	3.6	0.6	0.1	3.0	0.1	745.2	444.3
Alta.	66.9	650.4	2.5	363.9	2.7	10.3	1.7	0.2	8.5	0.2	1107.3	670.9
Sask.	1.3	122.5	0.6	11.2	0.6	2.3	0.4	0.0	1.9	0.0	140.8	11.6
Ontario	45.0	144.2	66.7	551.2	46.8	389.8	49.5	5.7	247.9	6.6	1553.3	301.0
Other Canada	9.3	81.2	36.1	284.0	50.2	26.0	4.3	0.5	21.5	0.6	513.7	211.1
Total	159.9	1340.2	106.7	1567.1	101.2	432.0	56.5	6.5	282.8	7.5	4060.3	1638.9

In general, the trends in GDP data parallel those in the employment data. Highlights of the cumulative GDP effect data are:

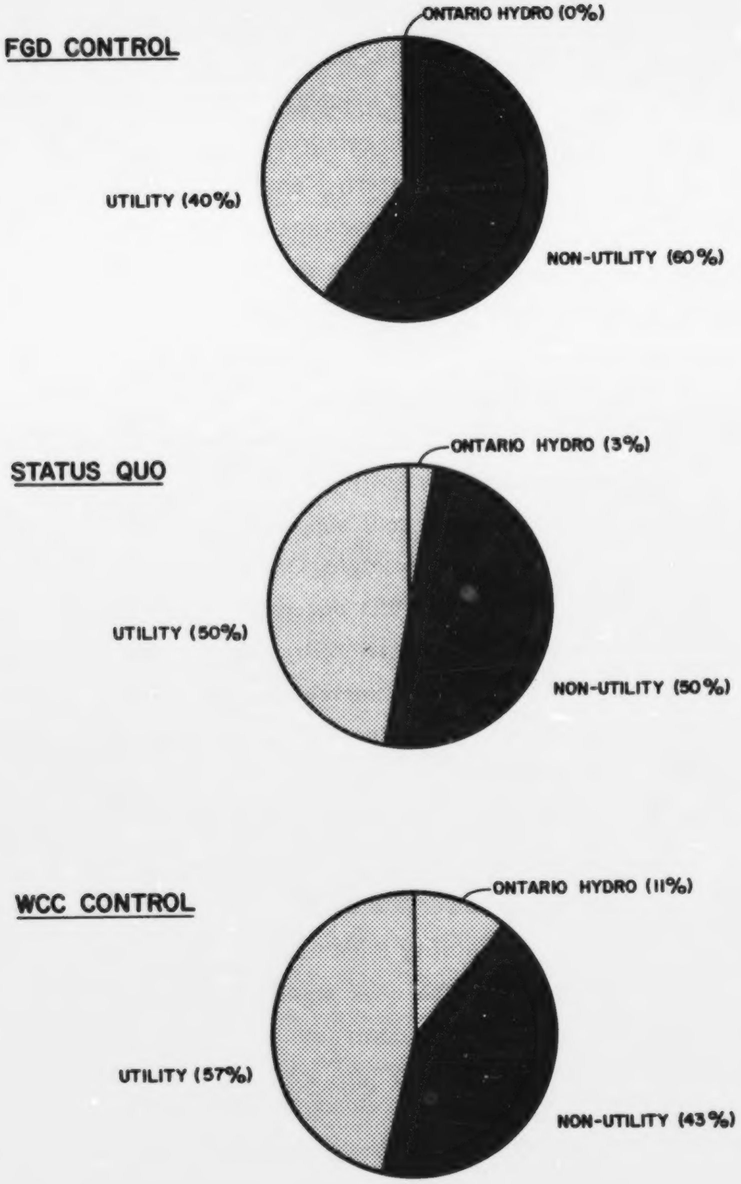
- Maintained or expanded use of western Canadian coal results in an overall increase in Canadian GDP compared to the FGD Control scenario. The incremental (discounted cumulative) GDP ranges from about $0.9 billion to $1.6 billion, depending on the scenario.
- Relative to the Status Quo, the FGD Control scenario results in a reduction in cumulative GDP on the order of $250 million for B.C. and $370 million for Alberta. These figures compare with provincial annual GDP in 1983 of $47 238 million (B.C.) and $56 539 million (Alberta). The overall impact of reduced coal use on the western provincial economies, therefore, is not expected to be large.
- Maintained or expanded use of western Canadian coal compared with the FGD Control scenario offers increments to GDP in Ontario, ranging from $234 million to $327 million.
- In general, the proportional GDP effects of the study scenarios are less than the proportional effects measured by employment. This is a result of discounting GDP time streams and is particularly apparent in the WCC Control scenario which has high levels of coal production and transportation late in the study period. Although employment under the WCC Control scenario is 17% greater than under the Mixed Controls scenario, GDP is only 6% greater.

3.5.3 Coal Industry and Community Stability. Expanding use of western Canadian coal from current levels may enhance stability in the western coal industry in two ways: through market diversification, and through the establishment of secure long-term contractual commitments. Through market diversification, producers are able to spread the risks of demand fluctuations in different markets. This basic business principle would, for example, mitigate the effects of depressed demand from one buyer on total mine production.

The coal mining industry could also benefit from the type of contracts governing sales to Ontario Hydro. Although not as stable as contracts between Alberta producers and local utilities, Ontario Hydro offers producers secure long-term purchase agreements. Contracts to export and industrial users are generally subject to greater fluctuations in actual purchases; spot market sales provide little or no security to producers.

In 1981, sales to utilities accounted for 54% of western Canadian coal production. Ontaro Hydro sales accounted for just over 7% (Canada West Foundation, 1980). Electric utility and Ontario Hydro shares of total projected demand in the year 2000, calculated for the four coal use scenarios, are shown in Figure 21.

Under the FGD Control scenario, utility contracts fall to 40% of total demand. Under the WCC Control scenario, utility contracts increase to 57% of total demand, of



Notes: Ontario Hydro forecasts based on Task Force coal consumption assumptions.
Forecasts for other markets are derived from "Western Canada's Coal, The Sleeping Giant"
Canada West Foundation, 1980.

FIGURE 21 ONTARIO HYDRO SHARE OF WESTERN CANADIAN BITUMINOUS COAL DEMAND (% Total Coal Demand in the Year 2000)

which Ontario Hydro accounts for 11%. These estimates indicate that expanded use of western Canadian coal could enhance stability in the mining industry by increasing the proportion of total demand devoted to long-term, stable purchases by electric utilities.

Potential benefits of market diversification are, however, compromised by three factors. First, the WCC Control scenario requires additional expenditures in mining equipment and capital. Expanded use of western Canadian coal, therefore, puts more investment funds at risk. Although these investments are protected by long-term contracts, tonnages actually purchased could vary so that when demand is depressed, higher fixed costs must be borne under the WCC Control scenario than under the FGD Control scenario.

Second, market diversification benefits may be offset by increased dependence on Ontario Hydro by individual operations. In such circumstances, fluctuations in Ontario Hydro demand may exacerbate production instability.

Third, the timing of incremental coal supply may affect short-term industry stability. In the WCC Control scenario, for example, Ontario Hydro's demand for western Canadian bituminous coal falls to zero in 1993 and 1994, but rises rapidly to about 14×10^6 t/yr (almost six times current consumption) by the year 2000. This time profile incurs shutdown and start-up costs, associated social dislocation, and requires a capital investment by coal producers of about $610 million in a four-year period (1996 to 1990). The coal mining industry, therefore, is likely to experience more instability over the planning period under the WCC Control scenario pattern of western Canadian coal use.

Reducing consumption of western Canadian coal from current levels, as occurs under the FGD Control scenario, would lower the share of long-term stable contracts and possibly subject producers to greater instability in demand than is currently experienced.

Reducing consumption would also have significant impact at the community level. Two mines with current Ontario Hydro contracts are heavily dependent on Ontario sales (60% to 80% of sales) and 500 to 800 jobs could be lost (with the associated economic dislocation) should shutdowns occur.

4 ENVIRONMENTAL IMPLICATIONS

The last set of criteria used for evaluating the four scenarios is overall environmental effects. The environmental evaluation takes into account the potential effects of coal mining, transportation, and combustion on land, water, and air. Environmental implications at each stage of the coal fuel cycle are illustrated in Figure 22.

Coal use scenarios are compared using five selected environmental indicators:

1) air emissions:
    - sulphur dioxide (SO_2),
    - nitrogen oxides (NO_x),
    - other particulate, and
    - trace metals;
2) land area affected;
3) water use and supply;
4) wastewaters; and
5) nuisance and safety.

The comparison focuses on differences between the FGD and WCC Control options as these represent the lowest and highest volumes of western Canadian coal consumption levels considered in this report.

4.1 Air Emissions

4.1.1 Sulphur Dioxide (SO_2). Although coal preparation plants and diesel fuel combustion in mining equipment, rail locomotives, and vessels emit SO_2, more than 99% of total emissions result from the combustion of coal at generating stations.

Both the FGD Control and WCC Control scenarios are designed to just meet the Ontario emission limits (for SO_2 and combined NO_x and SO_2), so they reduce total acid gas emissions over the 1985 to 2000 year period by the same amount (about 1620 kt). Total SO_2 and NO_x emissions from generating stations are about 3740 kt over the period. The Status Quo and Mixed Controls scenarios reduce emissions during the early 1990s even though reductions are not required to meet the control order. These scenarios result in total reductions over the 1985 to 2000 year period of about 1860 kt, for total emissions of about 3500 kt.

Although total emissions of SO_2 from thermal dryers at coal preparation plants are estimated to increase from 2020 t (1985 to 2000) under the Status Quo scenario to 2670 t (over the same period) under the WCC scenario, scrubbers installed on the facilities limit operating emissions to levels generally accepted by various provincial

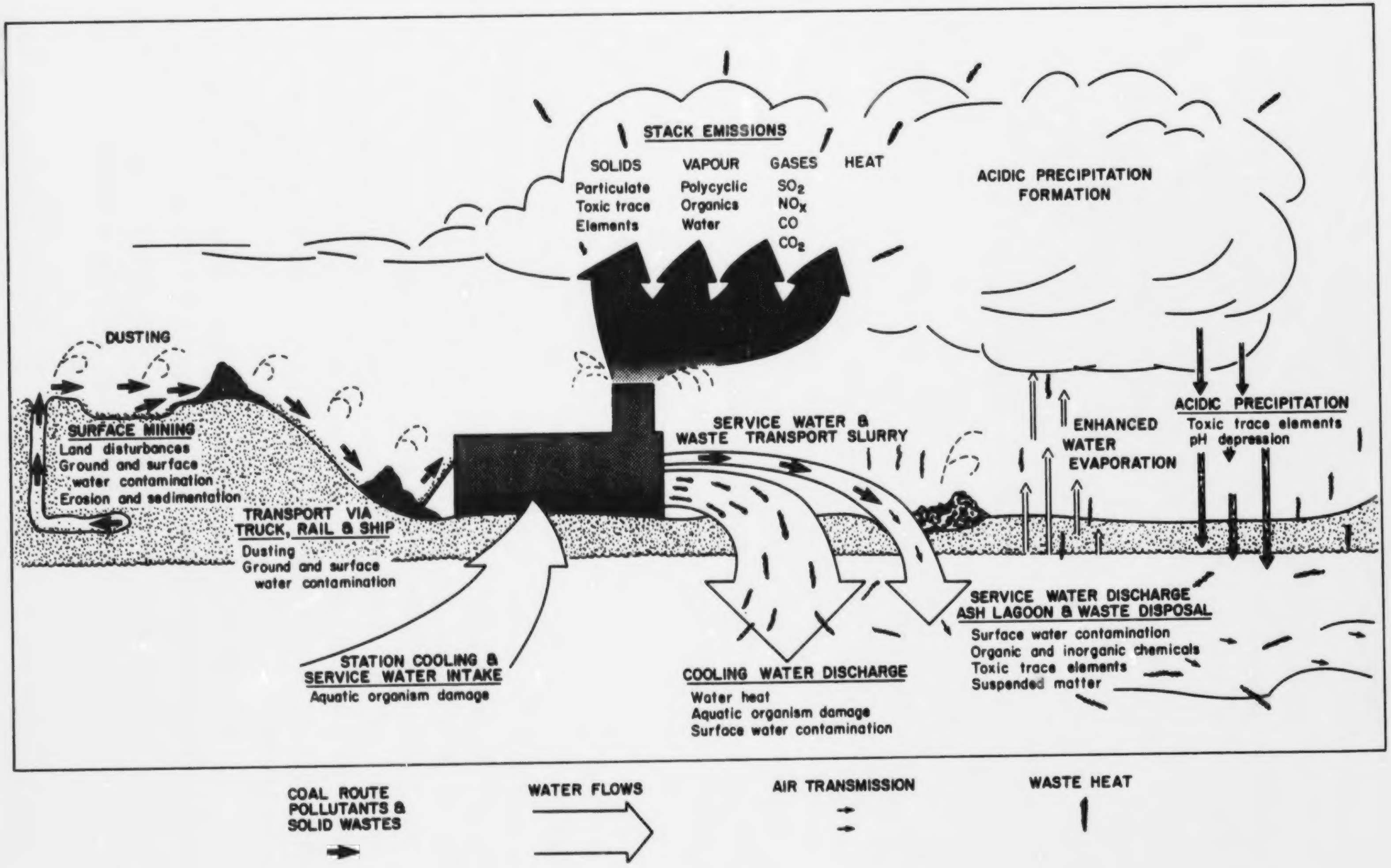

STACK EMISSIONS
SOLIDS
Particulate
Toxic trace
Elements
VAPOUR
Polycyclic
Organics
Water
GASES
SO_2
NO_x
CO
CO_2
HEAT
ACIDIC PRECIPITATION FORMATION
DUSTING
SURFACE MINING
Land disturbances
Ground and surface water contamination
Erosion and sedimentation
TRANSPORT VIA TRUCK, RAIL & SHIP
Dusting
Ground and surface water contamination
SERVICE WATER & WASTE TRANSPORT SLURRY
ENHANCED WATER EVAPORATION
ACIDIC PRECIPITATION
Toxic trace elements
pH depression
STATION COOLING & SERVICE WATER INTAKE
Aquatic organism damage
COOLING WATER DISCHARGE
Water heat
Aquatic organism damage
Surface water contamination
SERVICE WATER DISCHARGE ASH LAGOON & WASTE DISPOSAL
Surface water contamination
Organic and inorganic chemicals
Toxic trace elements
Suspended matter
COAL ROUTE POLLUTANTS & SOLID WASTES
WATER FLOWS
AIR TRANSMISSION
WASTE HEAT

FIGURE 22 ENVIRONMENTAL DISTURBANCES FROM CANADIAN COAL-FUELLED POWER GENERATION
(Environment Canada et al, 1980)

regulatory agencies. New or expanded coal preparation plants would be required to comply with these existing (or more stringent) provincial emission standards.

4.1.2 Nitrogen Oxides (NO_x). The primary source of NO_x emissions (more than 90%) is combustion of coal at the generating stations. Nitrogen oxide emission estimates are based on continuation of the Ontario Hydro program for low NO_x burner installations (i.e., all generating units are equipped by the year 2000). Although NO_x emissions vary with nitrogen content of the coal, emissions are assumed to be roughly the same (about 850 kt) whether western Canadian or U.S. coal is used.

4.1.3 Fugitive Dust. Although information is incomplete, the largest sources of increased fugitive dust emissions are mining and transportation. In mining, emissions rise from 56 kt for the FGD Control scenario to 167 kt for the WCC Control scenario. Transportation emissions are roughly split between rail and laker transport.

Fugitive dust emissions along the rail routes rise from 11 kt for the FGD Control scenario to 42 kt for the WCC Control scenario. All western Canadian coal mines are equipped with sealant spray apparatus to coat the coal loaded in the coal cars. Chemical sealant sprays reduce fugitive emissions by 95%, however, if dust complaints become more frequent as greater coal volumes are shipped, costly automated coal car covers may have to be considered.

Fugitive dust from laker transport rises from 61 kt in the FGD Control scenario to 95 kt in the WCC Control scenario. This includes both dusting losses and spilled fines that are washed overboard. The dust is generated primarily from product spillage while loading and unloading. Because all coal carried in lakers or ocean-going vessels is enclosed in covered holds, eliminating dust emissions en route, fugitive dusting en route should not occur.

Dust also originates from the stockpiles and coal handling operations at the terminals. The Thunder Bay terminal has pile sprays and other dust control equipment and any expanded facility would require similar or updated equipment. It is recognized, however, that problems during periods of high winds may persist or increase, possibly requiring temporary suspension in operations.

Increased coal volumes will add to the current problems of dust from coal not dumped from "empty" returning cars. There are at present no cost effective mitigation measures for this effect although methods are being investigated.

Fugitive dust at generating stations will increase roughly in proportion to the volume of coal handled and ash generated and would, therefore, be highest under the WCC

Control scenario. Also, dust from fly ash piles has generated complaints for many years. As annual fly ash production increases almost 40% under the WCC scenario, this concern is likely to grow.

4.1.4 Other Particulate.

Assuming that increased particulate collection capability is installed at generating stations to keep particulate emissions about the same, the major source of increases in particulate emissions would be thermal dryers at the preparation plants. An increase of about five kilotonnes over the FGD Control scenario is projected for the WCC Control scenario. Particulate emissions will, however, be limited to levels acceptable to provincial regulatory agencies by scrubbers in place in existing plants.

4.1.5 Trace Metals.

Varying percentages of the trace metals contained in coal are released during combustion. Typically, western Canadian coal from the foothills areas of Alberta and B.C. are lower in arsenic, chromium, cobalt, mercury, molybdenum, and nickel than U.S. coals, but higher in barium, boron, thorium, and uranium.

4.2 Water Use and Supply

Water is used in the mining and preparation of bituminous coal for:

- dust control in mines and on haulage roads;
- coal washing in preparation plants;
- equipment washdown; and
- sanitation.

Available data indicates that water withdrawal rates for mines in B.C. and Alberta range from 0.3 to 0.7 m^3/t of coal produced. In these provinces, where both surface and groundwater supplies are plentiful, competition for water resources is minimal.

As lignite is not subjected to wet preparation, withdrawals from surface water sources are primarily for dust control, equipment washdown, and sanitation. Even though withdrawals for lignite are much lower than for bituminous coal, they must be obtained from less abundant water supplies.

4.3 Land Areas Affected

Under the WCC Control option, land areas disturbed by mining rise from the current 10 km^2 to about 27 km^2 by the year 2000. Coal producing provinces require that the land be reclaimed in accordance with specific provincial regulations and guidelines. Furthermore, members of the industry have shown considerable diligence in meeting provincial requirements.

Land area requirements at the generating stations for coal storage and solid waste disposal are actually smaller under the WCC Control than under the FGD Control option because no land is required for FGD sludge disposal.

4.4 Wastewaters

Although projections are incomplete, wastewater volumes in both the coal mining and preparation areas could be expected to increase roughly in proportion to the increase in coal volumes. Current coal preparation plants in Alberta and B.C. practice 100% process water recycling and new plants would be expected to have similar facilities. Seepage and runoff waters from the mine and plant sites, tailings lagoons, coal storage areas, and refuse piles will increase as coal production increases (i.e., under the Mixed Controls and WCC Control scenarios). Current provincial regulations, however, require all operators to collect and treat most mine waters and surface runoff prior to discharge. New and/or expanded operations would have to follow these same mitigative practices.

Thunder Bay terminal has wastewater collection, recycle and treatment facilities. Any expansion would be expected to employ similar or updated control equipment, thereby minimizing wastewater concerns.

Washing of spilled coal from vessel decks could become problematic with increased vessel traffic. One incident of coal "fines" washing ashore and causing beach pollution was reported in the Strait of Georgia in 1984. Coal settling on harbour bottoms may damage environmentally sensitive areas.

Although there would be some increase in runoff and seepage volumes from coal piles and ash disposal areas at the generating stations, there would be only a slight net increase in total wastewaters generated in the WCC Control scenario because wastewaters from FGD systems would be avoided. Furthermore, wastewaters from western Canadian coal tend to be alkaline rather than acidic as are those from U.S. coal, thereby reducing concerns with dissolution of trace metals.

4.5 Nuisance and Safety

More rail traffic may cause some increases in nuisance concern and safety hazard as coal trains over 1.5 km in length increase in frequency from zero in Alberta and Saskatchewan under the FGD Control scenario to 55 times per week (8 times per day both directions) under the WCC Control scenario. There are currently 11 coal trains and about 290 trains of all types per week on the two rail lines. The WCC Control scenario would increase total rail traffic between B.C./Alberta and Ontario by about 19%. This would moderately increase road traffic disruption, noise, diesel combustion emissions, fugitive dust, and fires along the 2200 km rail route.

4.6 Summary of Comparison Between the FGD and WCC Control Scenarios

Both expanded use of western Canadian coal and installation of FGD have environmental implications (Tables 32 to 35). In the case of FGD controls, effects are largely limited to the combustion stage of the coal fuel cycle. Expanded use of western Canadian coal avoids some of these effects, but raises other environmental concerns associated with coal mining and transportation.

A comparison of the environmental implications of the WCC Control scenario with those of the FGD option yields these observations:

- SO_2 emissions would be similar;
- NO_x emissions at the stations - the largest source of NO_x emissions - would be about the same;
- notwithstanding the use of sealant sprays and other dust control equipment, fugitive dust emisssions would increase about threefold mainly due to mining and transportation, but with contributions from all sectors;
- particulate production from thermal dryers (during preparation) would increase fourfold, but emissions will likely be controlled (by scrubbing) to levels acceptable to provincial regulatory agencies;
- water consumption would not be a major concern since in Alberta and B.C., where expanded production of bituminous coal would increase water use sixfold, water supplies are plentiful (if lignite production were increased, water supplies may be strained and competition intensified in the water short areas of southern Saskatchewan);
- land area disruption would triple; however, the majority of this land (i.e., land disturbed by open pit mining) would be reclaimed in accordance with provincial requirements;
- solid waste production would double, mainly due to mining overburden removal; other wastes, which are more difficult to treat and dispose of, are: solid wastes from preparation; and solid wastes from combustion; these wastes would increase four times and 10% respectively;
- wastewater volumes to be collected, controlled and treated would increase 3 to 4 times in mining and 6 times in preparation; collection and treatment of most mine waters and surface runoff will, however, mitigate the impact of discharging these wastewaters; wastewater volumes would decrease slightly at generating stations;
- frequency of coal train passages would increase from none in Alberta and Saskatchewan and one every third day in Manitoba and Ontario (under the FGD Control scenario) to eight per day across the four provinces (under the WCC Control scenario), giving rise to potential increases in nuisance, health, and safety concerns.

TABLE 32 ENVIRONMENTAL IMPLICATIONS — MINING, 1985 to 2000

Parameter	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Coal Mined (x 10^6 t)				
- W. Can. Lignite	16.4	16.4	16.4	16.4
- W. Can. Bituminous	11.7	37.4	54.7	67.0
Surface Area Disturbed (ha)[a]	1010	1700	2300	2670
Overburden Produced (x 10^6 t)[b]	363	620	793	916
Freshwater Withdrawals (x 10^6 m^3)[c]	0.28	0.54	0.71	0.83
Water Losses (x 10^6 m^3)[d]	0.24	0.46	0.60	0.71
Wastewater Volumes (x 10^6 m^3)				
- Dewatering	not available			
- Pit and Sump Drainage	not available			
Air Emissions				
- Fugitive Dust (kt)[e]	56	108	142	167
- Diesel and Other (t)	not available			
- Hydrocarbons (x 10^6 m^3)[f]	110	220	280	330

Notes:

a estimated on the basis of 40 ha disturbed per million tonnes of lignite mined (strip), 30 ha disturbed per million tonnes bituminous coal mined (open-pit)

b estimated on the basis of a 15:1 stripping ratio for lignite, 10:1 ratio for bituminous coal (open-pit)

c for dust control, equipment maintenance and sanitation; estimated on the basis of 0.01 m^3/t coal mined

d evaporation from roads, ditches, etc., estimated on the basis of 85% evaporation

e estimated on the basis of 2.0 kg/t coal mined

f mainly methane; estimated on the basis 4 m^3/t of coal mined

TABLE 33 ENVIRONMENTAL IMPLICATIONS — PREPARATION, 1985 to 2000

Parameter	Scenario FGD Control	 Status Quo	 Mixed Controls	 WCC Control
Coal Prepared (x 10^6 t)				
- W. Can. Lignite	0	0	0	0
- W. Can. Bituminous	11.7	37.4	54.7	67.0
Solid Wastes (x 10^6 t)[a]	6	19	27	34
Air Emissions (t)				
- Fugitive Dust[b]	580	1870	2740	3350
- Particulate from Thermal Drying[c]	1050	3370	4920	6030
- SO_2 from Thermal Drying [d]	630	2020	2530	2670
- Particulate from Spontaneous Combustion	---------------- not available ----------			
Freshwater Withdrawals (x 10^6 m^3)[e]	5.8	18.7	27.4	33.5
Water Losses (x 10^6 m^3)[f]	1.5	4.7	6.9	8.4
Wastewater Volumes (x 10^6 m^3)[g]	6.7	21.5	31.4	38.5

Notes:

[a] estimated on the basis of 0.5 tonnes of solid waste per tonne of coal mined

[b] estimated on the basis of 0.05 kg of fugitive dust per tonne of coal processed

[c] estimated on the basis of 0.09 kg of fugitive dust per tonne of coal processed (based on range of 0.02 to 0.16 kg/t)

[d] estimated on the basis of 54 kg SO_2 emitted per kt of coal dried

[e] estimated on the basis of 0.5 m^3/t produced

[f] water lost in drying and/or contained in shipped product, estimated at 18% moisture in washed product (based on range of 16% to 20%)

[g] arithmetic difference between withdrawals and lost moisture

TABLE 34 ENVIRONMENTAL IMPLICATIONS — TRANSPORTATION, 1985 to 2000

Parameter	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Coal Transported (x 10^6 t)[a]				
- W. Can. Lignite	16.4	16.4	16.4	16.4
- W. Can. Bituminous	11.7	37.4	54.7	67.0
- U.S. Bituminous	102.3	81.5	66.8	55.5
Fugitive Dust				
- Rail (kt)[b]	11.4	25.5	35.0	41.8
- Terminal	not available			
- Laker (kt)				
W. Can. Bituminous Coal[c]	11.7	37.4	54.7	67.0
U.S. Bituminous Coal[d]	51.2	40.8	33.4	27.8
Diesel Emissions				
- Rail (NO_x, kt)[e]	13	30	41	49
Coal Train Frequency (times per wk, Year 2000)[f]				
- Alta./Sask.	0	10	28	54
- Man./Ont.	4	14	32	58

Notes:

a Rail Transportation Distances:
Lignite 1200 km (Bienfait to Thunder Bay)
Western Canadian Bituminous 2200 km (B.C./Alta. foothills to Thunder Bay)

b estimated on the basis of 95% dust control by sealant sprays, and an uncontrolled emission factor of 0.005 kg/t•km

c estimated on the basis of a handling loss emission factor of 0.1%

d estimated on the basis of a handling loss emission factor of 0.05% (only half the losses are on Canadian side of Great Lakes)

e estimated on the basis of 650 and 355 t NO_x emissions per million tonnes coal transported from B.C./Alta. and Sask., respectively

f estimated on the basis of 10 000 tonnes per train set, return trip included

TABLE 35 ENVIRONMENTAL IMPLICATIONS — COMBUSTION, 1985-2000

Parameter	Scenario			
	FGD Control	Status Quo	Mixed Controls	WCC Control
Coal Consumption (x 10^6 t)				
- W. Can. Lignite	16.4	16.4	16.4	16.4
- W. Can. Bituminous	11.7	37.4	54.7	67.0
- U.S. Bituminous	102.3	81.5	66.8	55.5
MW-years (x 1000) with FGD (on U.S. Coal)	27.9	19.7	10.4	0.0
Solid Waste Quantities (x 10^6 t)				
- Ash[a]	13.3	14.3	14.9	15.3
- FGD Sludge[b]	4.2	3.0	1.6	0.0
Total	17.5	17.3	16.5	15.3
Land Area-Coal Storage and Waste Disposal (ha)				
- Coal Storage [c]	70	73	76	81
- Ash Disposal[d]	89	96	100	102
- FGD Sludge Disposal[e]	42	30	16	0
Total	201	199	192	183
Air Emissions				
Fugitive Dust (kt)				
- Coal Storage/Handling				
- Ash Disposal	-------------- not available --------------			
Stack Emissions (kt)				
- SO_2	2902	2677	2677	2884
- NO_x	838	828	828	857
Total	3740	3505	3505	3741
Wastewaters (x 10^6 m^3)				
- Coal Storage [f]	10.1	10.5	10.9	11.7
- Ash Disposal[g]	1.3	1.4	1.4	1.5
- FGD Waste Disposal[h]	1.0	0.7	0.4	0.0
Total	12.4	12.6	12.7	13.2

Notes:

[a] estimated on the basis of 9.8% coal ash content of U.S. coal; 11.9% w. Cdn bituminous coal; and 11.5% of w. Cdn. lignite

[b] estimated on the basis of 0.15 kt sludge per MW-year capacity equipped with FGD, 65% capacity factor

[c] areas based on ratio of coal consumed in the year 2000 under the Status Quo, and WCC Control scenarios to coal consumed in the FGD Control scenario

[d] estimated on the basis of 10 m deep storage areas capable of storing 120 kt of ash per ha

[e] estimated on the basis of 12 m deep storage areas capable of storing 200 kt of FGD sludge per ha

[f] estimated on the basis of 9000 m^3/yr·ha (1.2 m/yr precipitation, 75% runoff)

[g] estimated on the basis of 10% of ash landfill area exposed at any one time, runoff and seepage rate of 9000 m^3/yr·ha

[h] estimated on the basis that 4 ha of sludge disposal area is exposed per 1000 MW-year of FGD operation, runoff and seepage rate of 9000 m^3/yr·ha

5 IMPLICATIONS OF EMERGING TECHNOLOGIES

The preceeding analyses are based on technologies that are currently available. Over the next decade, however, research and development will likely provide significant advances in coal preparation, transportation, and emission control.

It is not clear, at this time, how these new technologies may alter the relative attractiveness of each of the options for reducing acid gas emissions as previously discussed. Ongoing work in coal beneficiation and transportation, for example, could enhance the attractiveness of the western Canadian coal option, while SO_2 and NO_x control research suggest cheaper alternatives to FGD (wet scrubbing) may become available that would favour continued use of U.S. coal.

The purpose of this section is to provide some insight into relevant technological developments and their cost implications. Three specific areas of development are reviewed:

- coal preparation;
- emission control; and
- slurry pipelines.

5.1 Coal Preparation Technologies

Coal preparation technologies change coal properties in order to meet market specifications or increase its value as a fuel or process feedstock. Coal preparation includes processes for coal upgrading or beneficiation which may involve removal of moisture, removal of ash, removal of sulphur or changes in properties beneficial to the product end use. In some cases, the resulting product is more competitive in current markets; in other cases, the availability of the new product allows development of entirely new markets.

Coal beneficiation has been the focus of considerable research and development by the Alberta Research Council, the Saskatchewan Power Corporation (SPC), and the National Research Council, to name a few Canadian contributors. Some firms, such as the Western Energy Company from Montana, are exploring opportunities for application of proprietary coal beneficiation processes in Western Canada.

A complete review of each emerging technology is beyond the scope of this study. Instead, this section examines advanced physical coal cleaning and two promising beneficiation processes: beneficiation by oil agglomeration; and lignite beneficiation. The discussion of each technique includes a description of the process and its effect on utility generation. The discussions conclude with a brief assessment of costs and implications for enhancing the attractiveness of western Canadian coal.

5.1.1 Advanced Physical Coal Cleaning (PCC). Physical coal cleaning refers to the cleaning of run-of-mine (ROM) coal using differences in specific gravity between pure coal and the other main constituents of run-of-mine coal, such as clays, rock and pyrites. These can be separated from the raw coal by fine grinding and suspension in liquids. The degree of grinding required depends largely on the coal type. The optimum separation method depends on the size of the coal particles after grinding.

Ontario Hydro's current coal supplies from both the U.S. and Western Canada undergo conventional physical coal cleaning (washing) at the mine sites before being shipped. The coal is cleaned primarily to reduce the ash content and raise the heating value to meet Ontario Hydro specifications. Sulphur in the U.S. coal supply is reduced 20% to 30% (Ontario Hydro, 1980) by this means. Additional PCC could be applied to the Ontario Hydro coals to further reduce ash and sulphur and to reduce moisture content.

Three advanced methods of preparation are: the PCC I Process, the PCC II Process, and the PCC III Process (Monserco, 1985).

PCC I Process: Raw coal is crushed to three size fractions, each of which is processed separately. A dense medium vessel is used for the coarse coal, a dense medium cyclone for the intermediate sized coal, and froth flotation for the fine coal.

PCC II Process: After crushing, the coarse fraction is processed in dense medium cyclones operated at low specific gravity to produce a small overflow of highly cleaned coal. The bottoms from low-gravity cyclones are pumped to high-gravity cyclones to produce "middling" (medium quality coal) and refuse. The fine coal is recovered by froth flotation.

PCC III Process: About two-thirds of the crushed coal is a coarse fraction treated in dense medium cyclones. A fine coal fraction, amounting to about one-third of the crushed coal, is cleaned on concentrating tables. The remaining very fine coal fraction is thickened and filtered without cleaning, and added to the clean coal product.

These multi-stage coal cleaning processes are capable of increasing sulphur removal to about 25% to 35%. Advanced PCC appears to have significant potential for application to U.S. coals to reduce sulphur content. Ontario Hydro has considered application of a multistream advanced cleaning process to U.S. coal in order to concentrate the sulphur in a fraction of the coal stream. The process reduces the number of FGD units required (Ontario Hydro, 1980).

5.1.2 Coal Beneficiation by Oil Agglomeration. The concept of recovery of clean, fine coal from a coal/mineral matter/water slurry by means of oil agglomeration has been known for a long time. Clean coal particles are preferentially wetted by oil, so that when oil is added to the slurry and it is agitated sufficiently, agglomerates of clean coal are produced that permit separation from the aqueous phase by simple means such as screening.

This concept has been applied to Alberta thermal coals with positive results. Coal is finely ground with water while a heavy oil diluted with light oil is simultaneously added. With further conditioning, clean coal agglomerates are produced that have a low surface moisture content. The agglomerates are heated to remove the residual surface and inherent moisture, and to recover the light oil fraction which includes the diluent plus the light oil fraction in the heavy oil.

By this method, ash in the clean coal is minimized, the surface and inherent moisture are removed, and some of the oxygen is eliminated. Coal agglomerates have exhibited good handling and storage qualities, but demonstration on a commercial scale is still required.

Process Description. A beneficiation plant flow diagram is illustrated in Figure 23. Coal, of 50 mm x 0 size range, from the coal receiving and handling area is fed to a vibrating screen to produce an undersize stream (12.5 mm x 0) and an oversize stream (20 mm x 12.5). The oversize coal is passed to roll crushers which reduce the coal to 12.5 mm. The crushed coal is blended with the undersize stream for feeding to a cage mill where it is reduced to 1.7 mm before being fed to Szego mills. The Szego mills produce an efficient and economical method of preparing coal/oil mixtures by continuous wet grinding. Coal feed is combined with recycle water and agglomeration oil from the oil surge tank and fed to the Szego mills which fine grind the coal to less than 200 μm. Agglomeration oil is a mixture of light distillate oil and heavy oil (Lloydminster type).

The coal-water-oil mixture is fed to a low shear mix tank where recycle froth/water from the froth flotation unit is added and the components stirred to promote agglomeration of the coal particles to a size of approximately 500 μm. The slurry is passed to a dewatering screen to separate the underflowing ash slurry for disposal via the froth flotation unit. Coal from the screen is mixed with water, and the resulting slurry pumped to a second low shear mix tank to allow further agglomeration. The agglomerates are fed to a second dewatering screen. The ash/water underflow from the dewatering screen is recycled to the Szego mill coal feed stream. The low ash agglomerated coal product is conveyed to the low ash coal agglomerate surge bin.

The coal is dried in a rotary kiln by steam injection supplied by a fluid bed combustion boiler. Off gases, light oils, and water vapours are condensed and separated.

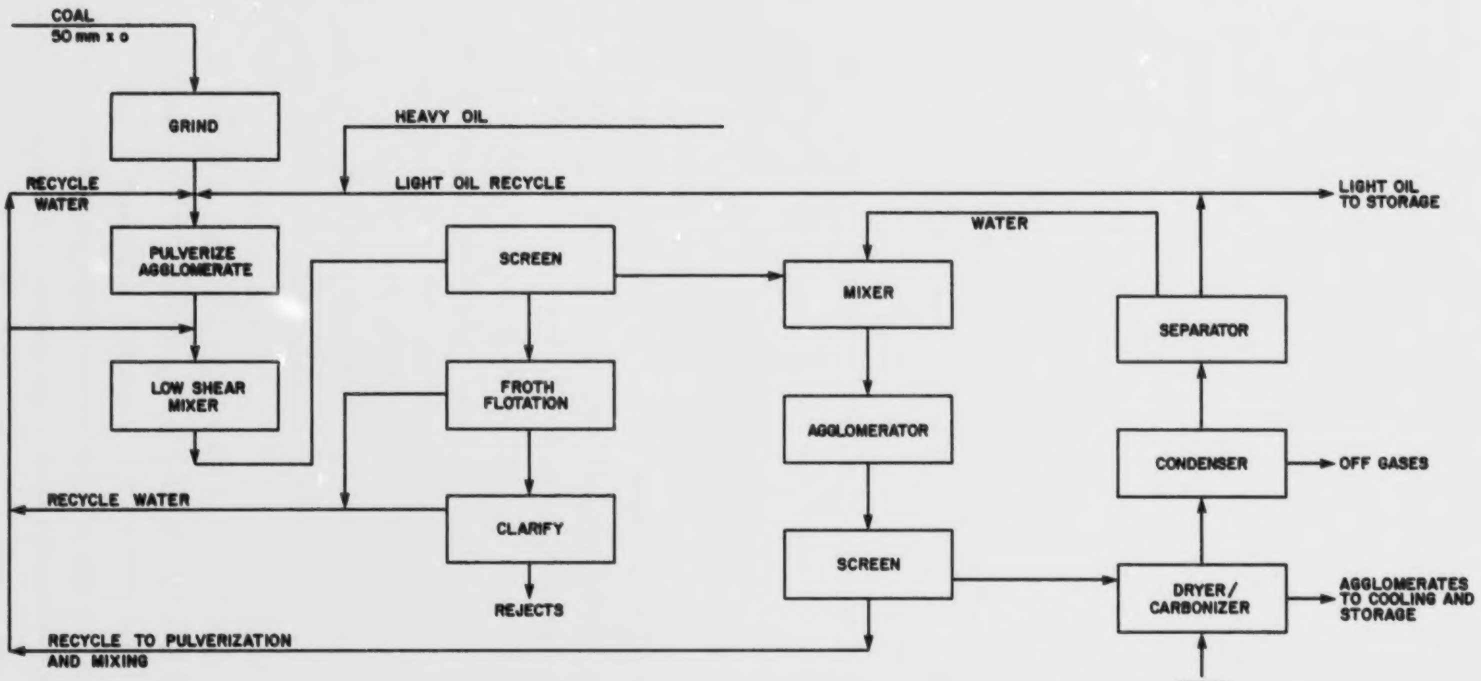


FIGURE 23 BENEFICIATION PLANT FLOW DIAGRAM (Oil Agglomeration)

Water is recycled to the mixer-agglomerater circuit. Light oil is recycled to the grinding circuit. The surplus oil is pumped to storage and sales. Boiler feed water is conditioned and passes through heat exchangers located in the vapour condenser unit. Dried and partially deoiled agglomerates are cooled and conveyed to storage or loadout.

Process Product. The end result of the oil agglomeration beneficiation process is a product that is low in ash and moisture, with a reduced oxygen content and a calorific value that has been further enhanced by the residual petroleum fraction remaining with the coal agglomerates. The coal is clean handling, of a uniform quality, and is expected to have excellent burning characteristics. Table 36 compares typical run-of-mine bituminous and subbituminous Alberta coal and eastern U.S. bituminous coal with coal beneficiated by means of agglomeration.

TABLE 36 TYPICAL PROPERTIES OF ALBERTA AND EASTERN UNITED STATES THERMAL COALS (Alberta Office of Coal Research & Technology, 1985)

	High Volatile Bituminous		Subbituminous		Eastern U.S.A. Bituminous
	Run-of-Mine	Agglomerates	Run-of-Mine	Agglomerates	
Moisture (%)	6 to 9	0.5 to 3.5	17 to 25	0.5 to 4.5	5.5 to 6.5
Ash (%)	15 to 30	5 to 6	7 to 20	5 to 6	7 to 9
Sulphur (%)	0.3 to 0.4	0.45 to 0.5	0.3 to .4	0.45 to 0.5	1.5 to 2.5
Oil (% remaining)	-	5 to 7	-	5 to 7	-
Volatiles (%)	35 to 40	30 to 35	30 to 38	22 to 27	33 to 37
Calorific Value:					
BTU/lb	7500-10 000	12 000-13 100	8000-9000	12 000-13 000	13 000-13 300
kJ/kg (x 10^3 kg)	17 450-23 250	29 775-30 475	18 600-20 900	29 300-30 225	30 225-30 925

Effect of Beneficiation on Utility Operation. It is expected that burn characteristics and energy values for Alberta agglomerated coal will be similar to referenced U.S. coals. In other words, there should not be any boiler derating when burning the Alberta product. It is expected that the slightly lower volatile content will be offset by the more porous character of the coal particles. Alternately, a somewhat lower carbonization temperature would increase the volatile content of the agglomerate. These assumptions are subject to revision based on results from Alberta coal agglomerate test burns carried out in late summer of 1985.

Sulphur Removal Credits and Ash Handling. Present federal guidelines for sulphur oxide emissions are a maximum of 0.26 kg SO_2 per GJ fired. The precise SO_2 emission level from Alberta agglomerated coal is not known at this time.

In the Alberta thermal coals, ash fusion temperatures are 160°C to 175°C lower (the Mynheer Seam is an exception) and sulphur content is 20% to 30% that of the referenced U.S. coals. Recent research and development in the use of calcium in the form of carbonate (limestone) or hydroxide (soda ash) presents interesting possibilities for western coal (including agglomerated coal). Calcium-containing additives in the amount of 1.5% to 2.0% of the coal may capture 60% to 70% of the sulphur present in Alberta thermal coals, at the same time adjusting upward the ash softening temperature. In this situation, the additional cost to the consumer would be that of the cost of 1.5% to 2.0% crushed and ground limestone. Ash handling costs would remain the same as for U.S. coal which is reputed to contain 7.92% ash.

Plant Costs. Rough (1982 dollar) costs for a plant of sufficient capacity to produce 1 x 10^6 t/yr of beneficiated coal agglomerates are:

Capital Expenditures	$ 73.8 million
- Direct	$ 56.8 million
- Indirect	$ 17.0 million
Operating Costs	
- Bituminous coal	$ 31.3 million/year
- Subbituminous coal	$ 23.1 million/year

(Alberta Office of Coal Research & Technology, 1985).

Converted to an annual basis (including capital recovery), the delivered cost of beneficiated bituminous coal is approximately $90 to $96/t, depending on the chosen rate of return on investment (ROI)*. If the increased heating value is taken into account, this represents a price reduction of about 10% from the base price of $87.75 used in the comparison of costs in Section 2.

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* Calculated as:

Capital repayment factor: (5% ROI, 10 year period)	$ 5.90 million
Operating costs	$31.29 million
Transportation costs	$52.75 million
Total	**$89.94 million** (or about $90/t)

5.1.3 SPC Lignite Beneficiation Process. From 1978 to 1983, experimental, economic, and engineering research was carried out on a process to upgrade and beneficiate Saskatchewan lignites. The result of these studies was an optimized process for producing a significantly beneficiated (rather than simply dried) lignite.

Process Description. Figure 24 presents a flow diagram for a lignite beneficiation plant. Run-of-mine lignite, crushed and screened to a suitable size range, is slurried with water for ease of handling. The slurry is heated and pressurized before being pumped into an ebullient bed reactor. Once in the reactor, the lignite is placed in intimate contact with saturated steam at 250°C to 276°C and 6 to 16.5 MPa pressure for a retention time of 5 to 15 minutes. Once the reaction is complete, the treated slurry is removed from the reactor, depressurized, dewatered by mechanical means, and cooled. Use of suitable heat exchangers and impulse turbines allows upwards of 95% of the process heat and pressure to be recovered and/or converted to electricity. This adds considerably to the favourable economics of the process.

During the 5 to 15 minute contact time in the reactor, several important changes occur to the lignite. Organic sodium is converted into a water soluble form, and is effectively leached from the lignite by the hot water in the reactor. Air pressure in the reactor oxidizes sulphur, which is removed from the lignite. Some oxygen is expelled from the lignite as carbon dioxide, increasing the heating value somewhat. Finally, the thermal treatment forces moisture out of the inner pores of the lignite and reduces its moisture reabsorption capacity.

Process Product. The result of these physical and chemical changes is a beneficiated lignite which is low in sodium and does not contribute to slagging and fouling. The sulphur content has been reduced to the point where it can be burned without flue gas desulphurization (FGD). The lignite can be safely and economically transported because its tendency to reabsorb moisture has been removed, reducing the risk of spontaneous combustion. Finally, the fuel is clean handling and burning, and of a uniform quality. Table 37 is a comparison of typical property ranges for run-of-mine (ROM) versus beneficiated lignite.

Effect of Beneficiation on Utility Operation. The benefits of burning beneficiated lignite are due not only to the obvious advantages in transportation and handling costs, but also to additional general utility costs related to the quality of the fuel and the ability to comply with SO_2 emission regulations. The following analysis is based on a 300 MW boiler unit firing 1.827×10^6/t of ROM lignite per year. It is assumed that

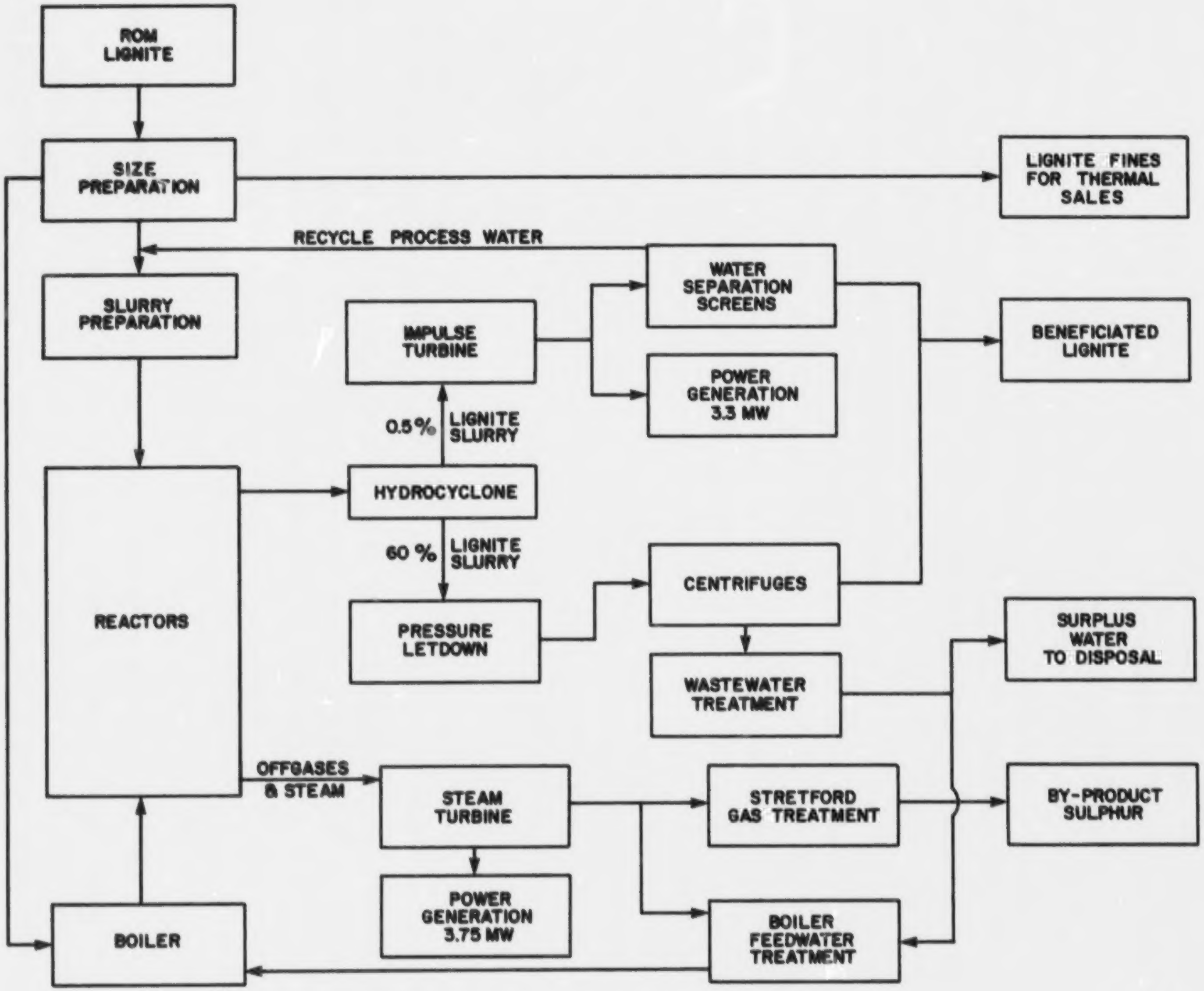

FIGURE 24 BENEFICIATION PLANT FLOW DIAGRAM (SPC Lignite Process)

TABLE 37 TYPICAL PHYSICAL AND CHEMICAL PROPERTY RANGES FOR RUN-OF-MINE (ROM) AND BENEFICIATED LIGNITE (Wet Basis) (Sask. Power Corp., 1985)

	ROM Lignite	Beneficiated Lignite
Ash (%)	9 to 11	12 to 14
Equilibrium Moisture (%)	28 to 34	9 to 15
Heating Value (GJ/t)	15.5 to 19.3	22.3 to 24
Sulphur (%)	0.35 to 0.70	0.2 to 0.4
Na_2O (as % of ash)	2 to 4	1 to 2
Hardgrove Index (HGI)	40 to 50	50
Dustiness	high	slight
Spontaneous Combustion	high	no
Slaking	high	slight

the overall boiler efficiency is 82.6%. Typical changes to the lignite as it is beneficiated are a reduction in equilibrium moisture from 33.5% to 14.8% and a reduction in sulphur from 0.55% to 0.31% sulphur on a wet basis (0.83% to 0.37% on a dry basis). At the same time, the heating value increases from 15.9 to 22.3 GJ/t.

Sulphur Removal Credits. Due to the reduction in sulphur content effected by the beneficiation process, a Canadian utility plant burning this lignite would require either reduced capacity sulphur removal equipment or none at all. The ROM lignite would produce 0.69 kg SO_2 per GJ, while the beneficiated lignite would produce 0.28 kg SO_2 per GJ. In practice, the calcium (Ca) content of the lignite mineral matter would probably capture 10% to 15% of the SO_2 prior to release to the stack; therefore, the beneficiated lignite would meet environmental regulations. This effect, however, will be ignored for this example.

Costs of sulphur removal by the beneficiation process can be compared with FGD sulphur removal costs. An SPC study of wet and dry FGD for Saskatchewan lignites indicates that an FGD system for a 300 MW boiler burning ROM lignite would require a rated capacity of 12.5 x 10^6 kg of sulphur removal per year (assuming an average load factor of 0.5), with a total removal cost of $7.96/t of ROM lignite. Total cost of sulphur removal on the beneficiated product, however, is estimated at $0.47/t of lignite.

Plant Costs. For a 5 x 10^6 t/yr beneficiation facility, total plant costs are $300 million (1982 dollars), or $340 million (1985 dollars). Operating costs are $98.9 x 10^6/yr, or $19.76/t of beneficiated product. This figure does not include capital recovery charges which are $5.33/t (at 5% ROI) to $10.78/t (at 15% ROI). Total annual plant costs, therefore, amount to about $25/t (5% ROI) or $28.75/t in 1985 dollars (Sask. Power Corp. 1985).

Retrofit of Existing Boilers to Beneficiated Lignite. Frequently, when a fuel switch is considered, significant resistance and concern about changes in the performance standards and operational practices of the generation plant materialize. This is particularly true where a switch to a fuel with a lower calorific value is planned. A primary objective of the fuel switch, however, is to reduce the overall cost of generating electricity with the cost of retrofitting (or derating) the boilers being more than offset by the fuel savings. A decision to switch fuel is based on consideration of costs and benefits accrued or expected for the new versus old fuel, and one should not expect that performance standards, design, or operational practices will remain unchanged.

Several issues related to fuel switch can be discussed and qualitatively evaluated for upgraded lignite and bituminous coals. Quantitative analysis of the expected magnitude of the derating is site- and fuel-specific, and would require consultation with boiler manufacturers to evaluate the proprietary boiler design data.

Table 38 compares typical combustion parameters and fuel characteristics for U.S. coal and beneficiated lignite. Based on Table 38, the following are general, qualitative conclusions on the fuel interchangeability and expected boiler performance with upgraded lignite.

1. **Boiler Derating**

   Review of the upgraded lignite analysis points to several potential problems due to higher moisture, higher ash content, and ash fouling probability. Areas that could be adversely affected are: 1) air heater capacity and pulverized fuel fan required for fuel drying; and 2) the ash collection system, including bottom ash removal and precipitator area. Assuming that the auxiliary systems can be changed and that a blend with U.S. coal is burned, no significant derating would result from burning upgraded lignite.

2. **Coal Handling and Pulverization**

   Standard mill throughput data suggest that additional pulverizing equipment will be required to retrofit boilers designed for U.S. coal to handle upgraded lignite or Alberta coals. Another approach to lower grindability of upgraded lignite may call for upgraded product with lower ash content. Actual equipment changes will vary

TABLE 38 SUMMARY OF CRITICAL DESIGN PARAMETERS AND FUEL PROPERTIES (Sask. Power Corp., 1985)

Area/Design Parameters	U.S. Eastern Bitiminous	Beneficiated Lignite
Furnace:		
Calorific Value (GJ/t)	30.38	22.30
Coal Handling and Pulverization:		
Coal Load (kg/GJ)	32.9	44.8
Hardgrove Grindability Index	80	50
Mill Production Rate (TPH/ft)*	0.38	0.09
Ash Handling:		
Ash Burden (kg/GJ)	2.61	5.52
Initial Fusion Temp (°C)	1350	1150
Sintering Strength (MPa)	2000	15
Ash Resistivity (ohm-cm)	1×10^{10}	1×10^{12}
Property (Wet Basis):		
Moisture (%)	5.86	14.80
Ash (%)	7.92	12.30
Volatiles (%)	35.50	26.10
Fixed Carbon (%)	50.72	46.80
Sulphur (%)	2.21	0.31
Heating Value (GJ/t)	30.38	22.30
Ash Burden (kg/GJ)	2.61	5.52
Coast at Source ($/t)	51.00	25 to 30.50

* TPH - tons per hour

from plant to plant since the existing layout and spare milling capacity will have to be incorporated into the coal handling equipment for the new fuel.

3. Ash Handling

Because of the low initial fusion temperature, burning upgraded lignite will definitely necessitate lower furnace exit temperatures to avoid serious fouling in the superheater and reheater sections. This will also be a major cause for boiler derating. Comparison of the ash resistivity data suggests that some form of flue gas conditioning will be required to increase the precipitator efficiency. The cost of treatment should not be excessive. The number and type of sootblowers should be sufficient to remove the fireside deposits from upgraded lignite considering the lower compressive strength of the upgrade lignite. Because of the high ash burden, additional tube erosion could be anticipated with upgraded lignite, although plant design could render actual increase insignificant.

Comparisons of Coal Costs. Table 39 provides a comparison of costs for ROM and beneficiated lignite and U.S. eastern bituminous coal. Owing to the large penalty paid for sulphur removal from U.S. coal, coal costs for beneficiated lignite and U.S. coal are similar. Both are significantly lower than ROM lignite costs. Based on a 300 MW power plant, total fuel costs of burning beneficiated lignite ranges from \$80 to \$87 million (1985 \$92 to \$100 million) compared with \$83.1 million (1985 \$95.6 million) for U.S. eastern bituminous coal. It must be emphasized that this analysis does not consider the boiler derating that could occur when firing lignite (as a result of moisture and ash levels). It is probable, however, that a beneficiated lignite /U.S. coal blend could be burned without derating. It should also be noted that refinements in the beneficiation process and additional processing to reduce ash content could further improve the quality of the beneficiated lignite and enhance its competitiveness.

5.2 Emerging Emission Control Technologies

There are a number of emerging emission control technologies and coal supply alternatives that have potential for reducing acid gas emissions from Ontario Hydro coal-fuelled generating stations. Each of these would improve the attractiveness of one or more of the possible combinations of Ontario Hydro coal supply.

Table 40 lists some of the developing technologies and coal supply alternatives. (This list is by no means exhaustive, but highlights examples of a number of specific technologies that appear to have potential). Also indicated are the coal type(s) to which they would be most applicable, the current status of the technology, and potential emission reductions.

Each of the technologies is discussed briefly, with assessment of their potential for improving the viability of increased western Canadian coal use in the Ontario Hydro system.

5.2.1 Dry Scrubbing. Dry scrubbing is similar to wet scrubbing (on which costs in preceding analyses are based), but uses less water. The liquid sorbent sprayed into the dryer chamber is dried by the hot flue gases, leaving dry powder residue. While drying, SO_2 in the flue gas is absorbed by atomized droplets of sorbent. Sulphur dioxide removal of about 70% is attainable. As with the wet limestone-gypsum process, the end product is mainly calcium sulphate. The dry process is not as efficient in its use of limestone, however, and to improve the SO_2 capture hydrated lime is often used as a sorbent.

TABLE 39 COMPARISON OF COSTS OF BURNING COALS IN SOUTHERN ONTARIO (1982$) (Sask. Power Corp., 1985).

	Beneficiated Lignite 5% DCF ROI	 15% DCF ROI	ROM Lignite	Eastern U.S. Bituminous
Fuel at Source ($/t)	25.09	30.54	10.00	51.00
Rail Transport ($/)	25.98	25.98	25.98	10.00
Terminal Charges ($/t)	4.50	4.50	4.50	2.00
Marine Transport ($/t)	6.50	6.50	6.50	2.00
Total Delivered Cost ($/t) (S. Ontario)	62.07	67.52	46.98	65.00
Million Tonnes/Year for 300 MW Boiler	1.28	1.28	1.83	0.94
Coal Cost ($ million/year)	79.4	86.4	86.0	61.1
Sulphur Reduction Cost ($ million/year)	0.6*	0.6	14.5*	22.0**
Total Coal Cost ($ million/year)	80.0	87.0	100.5	83.1

Notes: * assumes 50% capacity factor for FGD unit
** assumes 90% capacity factor for FGD unit

ROM = Run-of-Mine
DCF = Discounted Cash Flow
ROI = Return on Investment

Dry FGD has not been proven for the medium to high sulphur U.S. coals. It may be more applicable to a Canada/U.S. blend, which has a sulphur content comparable to coals from the mid-western U.S. where the technology has been demonstrated.

The somewhat lower capital cost of dry scrubbing suggests that application with blended coal might compare favourably with the wet FGD/U.S. coal option. Preliminary cost analyses indicate that when additional costs for the blended coal are already incurred, the added major capital expenditure for FGD would make this option no less expensive than going to 100% western Canadian coal, and considerably more expensive (from Ontario Hydro's perspective) than U.S. coal plus wet scrubbing.

The application of dry FGD, therefore, does not improve the attractiveness of using western Canadian coal in Ontario. In general, if the cost of FGD were to be incurred, it would be combined with the least expensive coal available (i.e., eastern U.S. bituminous).

TABLE 40 SUMMARY OF TECHNOLOGIES AND COAL SUPPLY ALTERNATIVES

Technology or Coal Supply Alternative	End Use Coal Type(s) Potentially Affected U.S.	Blend	Low-Sul. W. Can.	Current Status	Potential Emission Reduction (%) SO_2	NO_x
Dry FGD		•		fully demonstrated on low sulphur coals only	70	-
Combined Particulate/SO_2 (E-SOX)	•	•		limited pilot scale experiments	>90	-
Irradiation of Flue Gas	•	•		most advanced is electron beam at small pilot scale (3 MW); considerable development work needed	>90	>90
Low NO_x Burners	•	•	•	installed and operational at several Nanticoke G.S. units, planned installation at all Ontario Hydro stations	-	25
Sorbent Injection	•	•	•	undergoing full utility scale testing at Lakeview G.S. in Ontario, Boundary Dam G.S. in Sask.; a slagging burner version is being tested at Wabamun G.S. in Alberta	50	-
Fluidized Bed Combustion (FBC)	•	•	•	20 MW operational at Chatham in 1986	>90	40 to 80

5.2.2 Combined Particle/SO_2 Removal (E-SOX). This process is being developed as a low-cost retrofit system which combines advanced electrostatic precipitator (ESP) technology and spray dryer technology to remove particulate and SO_2 in the same physical equipment.

Advanced ESP technology provides the means for efficiently collecting particles in relatively small ESPs. In an existing three-section ESP, installing a precharger and replacing the normal discharge electrodes with large diameter wires in the last two sections will adequately increase particulate collection efficiency so that the first section can be made available for installation of a spray dryer system. A process flow diagram for E-SOX is presented in Figure 25.

Results of limited pilot scale experiments, mathematical modelling, and preliminary cost analysis show that this concept may prove to be technically and economically feasible.

The cost analysis shows that the major costs are associated with the lime handling system, followed by the costs of waste disposal -- the two components with the firmest costs. The costs of the cold-pipe precharger, large diameter wires, and spray system are relatively minor. Preliminary cost comparison with wet limestone FGD removal processes indicates that E-SOX should be at least competitive with current technology, and may offer significant cost advantages (Figure 26).

Experimental data and modelling based on those data show that modest (40% to 60%) levels of SO_2 removal are possible in an existing ESP with lime as the reagent. While still meeting particulate emission standards of 43 ng/J, high levels (over 90%) of SO_2 removal are possible with sodium carbonate as the reagent. At 50% to 60% SO_2 removal this process, combined with a blended coal, may achieve the level of SO_2 reduction required in the Ontario Hydro system in the late 1990s.

5.2.3 Irradiation of Flue Gases. Several removal processes for SO_2 and NO_x by irradiation of the flue gases are being researched. These include:

- electron beam (Avco/Ebara); and
- ultraviolet light (Concord Scientific).

The most advanced is the (Avco/Ebara) electron beam process, which has been under development for some 15 years in Japan and the United States (Avco/Ebara, 1980). The process is reportedly effective for both SO_2 and NO_x removal. Although it has currently been operated only at a small pilot scale (3 MW), it exemplifies an emerging flue gas cleaning technology with potential application in the next decade.

In this process, fly ash is first removed from the flue gas, which is then cooled by water injection, and ammonia is added. The gas stream then enters a shielded irradiation zone, where it is bombarded by electrons produced by 800 kV electron guns. The NO_x and SO_2 are oxidized by an incompletely understood free-radical mechanism to

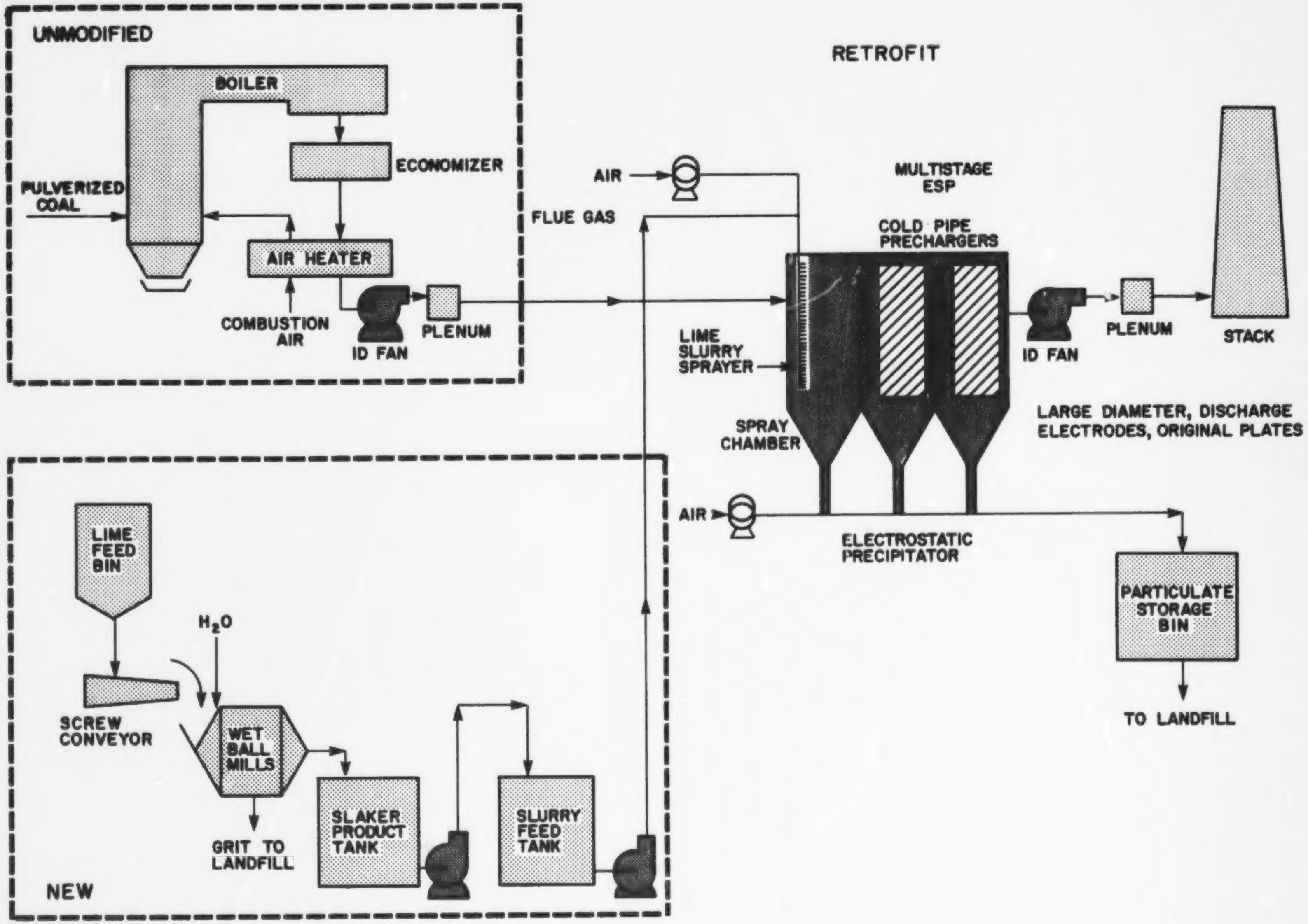

FIGURE 25 PROCESS FLOW DIAGRAM FOR E-SOX

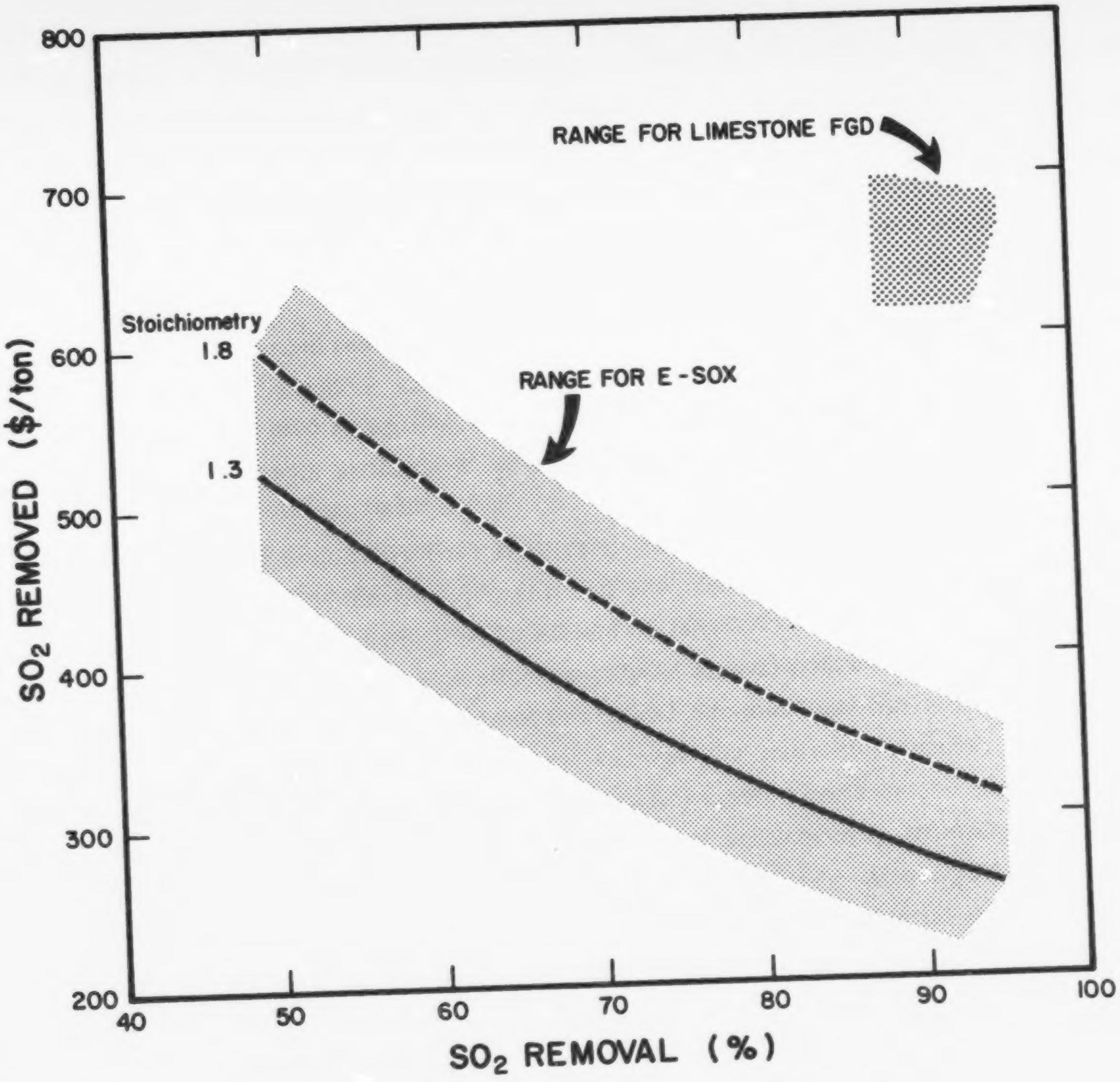

FIGURE 26 COST EFFECTIVENESS OF E-SOX PROCESS

give sulphuric acid and nitric acid, which combine with the ammonia to form ammonium sulphate and ammonium sulphate nitrate. The ammonium salts are removed from the gas stream for possible sale as fertilizer.

In a variant of this process (Research-Cottrell, Inc.) lime is injected ahead of the electron beam device, and eventually produces calcium nitrate and calcium sulphate at the process outlet.

Cost savings of 40% over conventional FGD have been estimated. The process is likely to have some drawbacks, however, including the cost of ammonia, a higher energy penalty, possible radiation, and material corrosion problems due to the generation of free acids in the flue gas.

There is no indication of the kind of coal to which this process would be best suited. If it were to prove effective in the long term, it would probably be combined with the least cost coal (U.S. coal in Ontario).

5.2.4 NO_x Control Technologies. Control of NO_x becomes increasingly important in the Ontario Hydro system as coal consumption increases. Uncontrolled NO_x emissions with the projected higher coal use in the year 2000 would use up 40% to 45% of the total 215 kt Ontario emission limit, requiring that SO_2 be reduced significantly below the 175 kt SO_2 limit.

The objective in NO_x control is to limit the formation of fuel NO_x as well as thermal NO_x. Fuel NO_x results from the fuel nitrogen; thermal NO_x originates from the combustion air. The thermochemical formation of NO_x from nitrogen is a temperature dependent equilibrium which favours NO_x at normal combustion temperatures (1370°C to 1650°C) of pulverized coal boilers. Lower temperatures (e.g., about 850°C in fluidized bed boilers) reduce equilibrium NO_x levels -- the kinetics and microscale fuel chemistry of the dynamic combustion process (e.g., air/coal ratios, coal and nitrogen volatization, turbulence patterns, intermediate oxidation/reduction reactions, local residence time) also change NO_x levels.

The formation of NO_x is not fully understood. Research into some variables has allowed commercial development of combustion control technologies. Common to these technologies is the principle of staged combustion -- a modified burner and/or boiler design which permits better control of the combustion process with respect to:

- fuel flow and air mixing,
- residence time, and
- combustion temperature.

Overfire air and dual register burners (with compartment windboxes) have been incorporated in a number of Canadian boilers since 1972. Eventually all Ontario Hydro units will be fitted with such systems. Reductions of 25% of NO_x emissions from wall-fired boilers can be achieved by retrofitting low NO_x burners at a cost of approximately $2/kW (1980) or $120 to $450/t of NO_x removed (depending on the station capacity factor).

For tangentially-fired boilers, retrofitting overfire air ports to the boilers would cost approximately $1/kW plus operating cost of about $0.05 million/kWh. If it is assumed that 25% reductions in NO_x emissions could be achieved by this modification, it would cost about $400/t of NO_x removed (Ontario Hydro, 1980).

The reduction of NO_x is equally applicable to U.S. and western Canadian coals. It does not necessarily enhance the attractiveness of western Canadian coal over U.S. coal; rather it permits the 215 kt emission limit to be met with a smaller quantity of western Canadian coal, thereby reducing the overall cost of meeting the limit.

5.2.5 **Sorbent Injection.** Sorbent injection systems often combine a low NO_x burner with the injection of an SO_2 sorbent (e.g., limestone) such that reductions in both SO_2 and NO_x are achieved. One variation of sorbent injection is the "lime injection multi-stage burner", commonly referred to as LIMB.

The early LIMB processes added the calcium-based sorbent to the coal before the pulverizer. The more recent developments have installed separate injection points at furnace elevations above the uppermost burner row, where the gas temperature is optimal for the sulphation reaction, i.e., the combination of calcium and sulphur to form calcium sulphate. The latter is subsequently removed from the gas stream by the dust removal equipment.

Because inherent lower flame temperatures provide appropriate conditions for both NO_x reduction and SO_2 capture, the reduction of SO_2 and NO_x are complementary when sorbent injection is applied in combination with the low NO_x burner technology.

Sorbent injection systems are currently being demonstrated at utility scale at Ontario Hydro's Lakeview G.S. and at Saskatchewan Power Corporation's Boundary Dam G.S. The level of interest generated from utilities suggests it may have potential as an acid gas emissions control technology. Although tests are not conclusive, SO_2 removal efficiency of 50% may be achievable. This removal efficiency is much lower than that of FGD, but capital costs of sorbent injection systems (for example, LIMB) are only 25% to 35% of FGD costs and the operating costs are about half.

Another type of sorbent injection system is the slagging burner for which testing is planned at one unit of TransAlta's Wabamun G.S. In this process, combustion and chemical reactions to remove the sulphur and oxides of nitrogen take place in the burner itself, not the boiler (as is the case with in-furnace sorbent injection). Calcium is added in the form of limestone and pulverized with the coal being fed to the burners.

Although application of this process may be limited by physical plant restrictions, it has potential to reduce SO_2 emissions by 70% and NO_x emissions by 80%.

Drawbacks of sorbent injection are: 1) increased particulate emissions if modern particulate control devices (e.g., baghouses) are not installed; and 2) the large quantities of potentially reactive solid wastes requiring disposal.

Because less sorbent is required with lower sulphur coals, this technology may be better suited to a western Canadian/U.S. coal blend than to straight U.S. coal; therefore, it may enhance the attractiveness of using western coal in Ontario. Preliminary cost analysis shows, however, that both U.S. coal with LIMB or wet FGD and straight western Canadian coal to meet emission limits would be cheaper than LIMB with a blended coal.

5.2.6 Fluidized Bed Combustion (FBC). In fluidized bed combustion, crushed coal is burned in a bed of granular, nonvolatile material. There are two basic types of atmospheric FBC designs: bubbling and circulating. In bubbling FBC designs, combustion air is passed through a grid plate at sufficient velocity to fluidize the (sorbent) bed material which normally consists of limestone or dolomite and coal ash. Fuel and sorbent are fed to the bed by various techniques, including air distributors at the bottom of the bed, pneumatic transport and addition through feed points located within the bed, and surface feeding using devices such as a spreader-stoker (Environment Canada, 1982).

Coal is ignited and mixes turbulently with inert particles, maintaining a relatively stable temperature throughout the bed. The bed normally operates within a temperature range of 820°C to 920°C. Heat transfer surfaces are located both within and outside the bed, and consist of boiler tubes placed within the bed and membrane-type waterwalls enclosing the combustion zone. Convective or radiative heat transfer surfaces can also be placed directly above the bed, downstream of the combustion zone. The direct impact of the hot particles against the heat transfer surfaces submerged in the bed yields a much higher rate of heat transfer than is created in a conventional boiler.

FBC development in Canada favours circulating FBC rather than the conventional bubbling design. Figure 27 shows a typical circulating fluidized bed boiler. Circulating designs are thought to be more practical for larger units. Unlike bubbling FBC, they have no clearly defined bed and overbed combustion zones. The fluidized mixture of fuel and sorbent commence combustion in a primary fluidizing vessel, in which they ascend and flow over to an adjacent parallel chamber. In this second vessel the flow direction is downward. Hot gases are removed while solid material descends to the

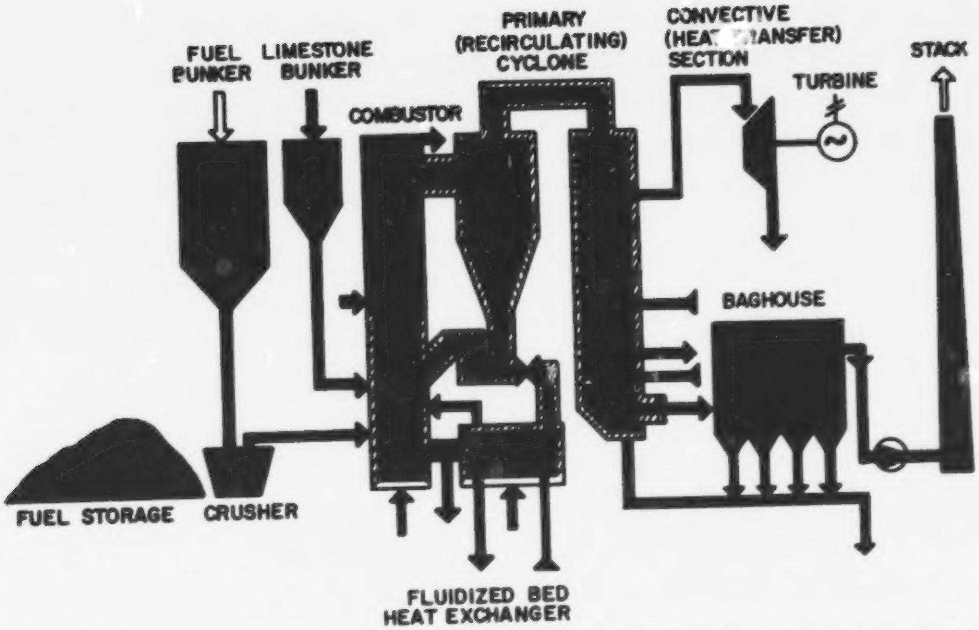
FUEL BUNKER
LIMESTONE BUNKER
COMBUSTOR
PRIMARY (RECIRCULATING) CYCLONE
CONVECTIVE (HEAT TRANSFER) SECTION
TURBINE
STACK
BAGHOUSE
FUEL STORAGE
CRUSHER
FLUIDIZED BED HEAT EXCHANGER

FIGURE 27 CIRCULATING FLUIDIZED BED BOILER FLOW SCHEMATIC

bottom. The incombustible ash is removed at this point, and the unburned fuel and unreacted limestone are reinjected into the fluidizing vessel.

Fluidized bed combustion technology is being demonstrated for various sizes in Europe and North America and more than 100 units are in operation or under construction worldwide. In Canada, a bubbling fluid bed is operating as a small heating plant boiler at the Summerside, P.E.I. military base. A 20 MW circulating fluid bed boiler is being constructed at the New Brunswick Electric Power Commission's Chatham G.S. and will be in operation in late 1986. The Nova Scotia Power Corporation is currently assessing the feasibility of installing a 150 MW unit at the Tuft's Cove G.S., potentially for operation in the early 1990s. Based on current worldwide operations; Ontario Hydro may have the option of building FBC units (larger than 150 MW) in the late 1990s.

Although FBC is capable of reducing SO_2 emissions by more than 90% and NO_x emissions by more than 40%, it also produces large quantities of a highly reactive CaO solid waste which may be difficult to handle and dispose of.

FBC can operate with a wide range of coal types but it would not likely enhance the attractiveness of western Canadian coal use in Ontario. If the expense of retrofitting boilers to FBC or building new FBC boilers were to be incurred, economics would dictate that it be combined with the lowest cost coal.

FBC has the capability of burning high-sulphur coal cleaning rejects, and it could have limited application in combination with pulverized coal units burning cleaned coal. FBC could improve the viability of coal cleaning by reducing wastes. This, however, would probably favour cleaning processes applied to the cheaper U.S. coal.

5.3 Slurry Pipelines

In the transportation area, slurry pipelines hold promise for the future. A cooperative study between TransMountain Pipelines Company and the Alberta government is underway to determine the engineering, economic, and environmental feasibility of using the TransMountain crude oil pipeline from Edmonton to Vancouver to batch-transport crude oil and coal slurries. The study examines the use of more finely ground slurries, with a coal ratio of up to 75% of total weight (compared with the more common ratio of 50%) to make the slurry suitable for long distance pumping. Higher ratios of coal allow a smaller line to transport a given amount of coal and, because the slurry can be fed directly into a boiler, the need for dewatering facilities at the point of delivery is eliminated. The change in slurry composition also makes it easier to batch ship coal in existing oil lines which, if there is spare pipeline capacity, avoids the cost of constructing a new dedicated line.

Issues being addressed in the study include:

- economic size of batches (absolute and as increment of total mine output);
- review of exportable western coals and possible coal/water preparation processes;
- resource needs;
- changes/additions to pipeline system; and
- environmental implications and worst case scenarios.

The study is in step with TransMountain's engineering analysis evaluations. Due to the preliminary nature of the work to date, only a cursory comparison of the smaller volume technology with rail costs is possible. Further work required to more fully evaluate the pipeline's competitive position includes:

- a further look at the likely range of rail rates and the future trend in these rates with various assumptions of inflation; and
- additional estimates to include all preparation, handling, and delivery costs on a completely consistent basis.

Using the costs prepared and allocating the costs of upgrading the line to coal transportation, transporting 5×10^6 t/yr by pipeline is still slightly higher than by rail. A throughput of 2×10^6 t/yr is also examined in the study, but found to be less economic than 5 x 10^6 t/yr. A separate study on the application of the Densecoal process is underway at one Alberta coal company.

The potential for slurry pipelines to reduce coal transportation costs, and enhance the attractiveness of expanded use of western Canadian coal, appears to be limited for now. Many factors, including rapid advances in design for long distance slurry pipelines could, however, change this conclusion.

Alternatives to the coal/water mixture previously discussed may also hold some potential. For example, if heavy oils from Cold Lake, Alberta were moved to Ontario for refining, coal may be needed in the refining process. In such circumstances, the cost of the pipeline could be borne by the mixture of oil and coal. The competitive outlook for coal/oil mixtures, as indicated in a 1973 study on the feasibility of transporting coal and crude oil through Interprovincial Pipeline Company's line, will depend on market conditions (relative costs and supply considerations) of both coal and oil. Detailed examination of future price and demand trends is beyond the scope of this Task Force.

5.4 Summary of Evolving Technologies to Enhance the Viability of Western Canadian Coal

Technologies that will upgrade the quality of western Canadian coal offer the greatest potential for enhancing its attractiveness to Ontario Hydro. If the heat content and combustion characteristics can be improved at a reasonably low cost:

1) the cost of transporting and handling the coal, on a heat content basis, will be reduced; and
2) concerns and uncertainties with burning the coal in high percentages at the generating stations without boiler derating will be reduced.

There is a fairly narrow cost margin to work with in upgrading western Canadian bituminous coal. Because of the higher mining costs, its price delivered to Ontario Hydro is higher on a heat content basis than the price of subbituminous coal or lignite. Taking the cost of upgrading into account, it is unlikely that the price could be reduced much more than about 10% on a heat content basis.

On the other hand, lignite and subbituminous coal mining costs are in the \$10/t to \$15/t range, some \$20/t to \$30/t less than the mining costs of bituminous coal. Because these coals are closer to the southern Ontario market, transportation costs are also less. This leaves a substantial cost margin for upgrading, particularly on subbituminous coal. If the heat content of subbituminous coal can be increased by 30%

(from 21 000 to 27 000 kJ/kg) at \$5/t, the delivered price of the upgraded coal would be about 27% lower (on a heat content basis) than the current delivered price of bituminous coal.

In contrast to upgrading technologies, the development of more efficient, less costly emission control technologies will tend to favour continued use of less expensive U.S. coal. There may be low cost removal technologies, however, that when combined with a blended western Canadian and U.S. coal, will yield lower overall costs than U.S. coal plus FGD. This does not appear to be the case with sorbent injection. When the cost of supplying blended coal is included, sorbent injection tends to be more costly than using straight western Canadian coal. Evolving low cost technologies, such as E-SOX with only partial SO_2 removal capability, may improve the economics of using blended coal; therefore, improving the viability of western Canadian coal in the system.

Coal slurry pipelines have limited potential to be competitive in the medium term. In the long term, if a high volume sustained market is assured they may provide economic advantages over other means of transportation, and improve the attractiveness of western Canadian coal.

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APPENDIX A

BASIC DATA, ASSUMPTIONS AND SOURCES

GENERAL ASSUMPTIONS

Item	Assumption	Source
Time Frame	- 1985 to 2000 (no information on system structure beyond 2000 is available)	- Task Force
Inflation Rate	- constant 1985 dollars (note: a real price increase is incorporated into U.S. coal prices - see below)	- Task Force
Discount Rates (real)	- Ontario Hydro: 6.6% - Mine & Transp. (excl. rail): 7.1%	- Mine & Transp.: Globe & Mail (corporate bond yield) - C & Em.: Ont. Hydro - Statistics Canada
	- social: 10% (sensitivity analyses for 5% and 15%)	- Treasury Board Guidelines
Amortization Periods	- 10 years for transportation and mine capital expenditures - 20 years for Ont. Hydro station modifications and FGD	- Mine: EMR - Transp.: TCda - C & Em: Env. Cda

- C & Em. - Combustion and Emissions
- TCda - Transport Canada
- Transp. - Transportation
- Env. Cda - Environment Canada
- EMR - Energy, Mines and Resources

COAL VOLUMES

FGD Control Scenario
(kt)

Year	U.S. Coal*	W. Cdn. Bit.	W. Cdn. Lignite
1985	7 810	2 310	830
1986	4 910	1 900	1 040
1987	4 480	1 600	1 040
1988	4 040	1 300	1 040
1989	3 240	1 200	1 040
1990	4 310	1 200	1 040
1991	3 490	1 200	1 040
1992	2 840	1 000	1 040
1993	4 480	0	1 040
1994	5 170	0	1 040
1995	6 430	0	1 040
1996	7 690	0	1 040
1997	8 900	0	1 040
1998	10 120	0	1 040
1999	11 510	0	1 040
2000	12 910	0	1 040

Status Quo Scenario
(kt)

Year	U.S. Coal*	W. Cdn. Bit.	W. Cdn. Lignite
1985	7 810	2 310	830
1986	4 560	2 330	1 040
1987	3 880	2 330	1 040
1988	3 190	2 330	1 040
1989	2 300	2 330	1 040
1990	3 370	2 330	1 040
1991	2 840	2 330	1 040
1992	2 310	1 660	1 040
1993	2 750	2 330	1 040
1994	3 200	2 330	1 040
1995	4 460	2 330	1 040
1996	5 710	2 340	1 010
1997	6 930	2 360	1 040
1998	8 120	2 380	1 040
1999	9 370	2 610	1 040
2000	10 690	2 780	1 040

* includes energy penalty for FGD

Mixed Controls Scenario
(kt)

Year	U.S. Coal*	W. Cdn. Bit.	W. Cdn. Lignite
1985	7 810	2 310	830
1986	4 560	2 330	1 040
1987	3 880	2 330	1 040
1988	3 190	2 330	1 040
1989	2 300	2 330	1 040
1990	3 370	2 330	1 040
1991	2 840	2 330	1 040
1992	2 310	1 660	1 040
1993	2 750	2 330	1 040
1994	3 200	2 330	1 040
1995	3 460	3 480	1 040
1996	3 890	4 530	1 040
1997	4 900	4 850	1 040
1998	5 350	5 620	1 040
1999	6 180	6 320	1 040
2000	6 760	7 320	1 040

WCC Control Scenario
(kt)

Year	U.S. Coal*	W. Cdn. Bit.	W. Cdn. Lignite
1985	7 810	2 310	830
1986	4 910	1 900	1 040
1987	4 480	1 600	1 040
1988	4 040	1 300	1 040
1989	3 240	1 200	1 040
1990	4 310	1 200	1 040
1991	3 490	1 200	1 040
1992	2 840	1 000	1 040
1993	4 480	0	1 040
1994	3 560	1 920	1 040
1995	3 110	3 900	1 040
1996	2 660	5 920	1 040
1997	2 220	7 980	1 040
1998	1 890	9 660	1 040
1999	1 440	11 820	1 040
2000	900	14 120	1 040

* includes energy penalty for FGD

100% WCC Scenario
(kt)

Year	U.S. Coal	W. Cdn. Bit.	W. Cdn. Lignite
1985	7 810	2 310	830
1986	4 560	2 330	1 040
1987	3 880	2 330	1 040
1988	2 070	3 670	1 040
1989	0	5 100	1 040
1990	0	6 340	1 040
1991	0	5 360	1 040
1992	0	4 380	1 040
1993	0	5 260	1 040
1994	0	6 130	1 040
1995	0	7 580	1 040
1996	0	9 060	1 040
1997	0	10 460	1 040
1998	0	11 870	1 040
1999	0	13 500	1 040
2000	0	15 120	1 040

No Control Scenario
(kt)

Year	U.S. Coal	W. Cdn. Bit.	W. Cdn. Lignite
1985	7 810	2 310	830
1986	4 910	1 900	1 040
1987	4 480	1 600	1 040
1988	4 040	1 300	1 040
1989	3 240	1 200	1 040
1990	4 310	1 200	1 040
1991	3 490	1 200	1 040
1992	2 840	1 000	1 040
1993	4 480	0	1 040
1994	5 130	0	1 040
1995	6 350	0	1 040
1996	7 570	0	1 040
1997	8 740	0	1 040
1998	9 910	0	1 040
1999	11 260	0	1 040
2000	12 620	0	1 040

ONTARIO HYDRO
ESTIMATED ELECTRICITY DEMAND

(GWh) Environment Canada

	Coal-Fired	Total
1985	32 040	124 830
1986	31 154	129 200
1987	34 904	132 950
1988	26 661	136 270
1989	23 764	139 680
1990	27 527	143 170
1991	24 254	146 750
1992	21 887	150 420
1993	25 647	154 180
1994	26 678	158 030
1995	30 628	161 980
1996	34 678	166 030
1997	38 828	170 180
1998	42 339	174 440
1999	46 699	178 800
2000	51 169	183 270

CAPITAL EXPENDITURES

FGD Control Scenario
(1985 $ millions)

		Transportation							
Year	Mine	Rail	Terminal	Vessel	Total	Combustion	ESP	FGD*	Total
1985	0	0	0	0	0	0	0	0	0
1986	0	0	0	0	0	0	0	0	0
1987	0	0	0	0	0	0	0	0	0
1988	0	0	0	0	0	0	0	0	0
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	45.3	45.3
1992	0	0	0	0	0	0	0	113.4	113.4
1993	0	0	0	0	0	0	0	249.3	249.3
1994	0	0	0	0	0	0	0	272.0	272.0
1995	0	0	0	0	0	0	0	272.0	272.0
1996	0	0	0	0	0	0	0	272.0	272.0
1997	0	0	0	0	0	0	0	272.0	272.0
1998	0	0	0	0	0	0	0	286.0	286.0
1999	0	0	0	0	0	0	0	150.0	150.0
2000	0	0	0	0	0	0	0	0	0

* FGD installed on eight units at Nanticoke, four at Lambton and three at Lakeview.

Status Quo Scenario
(1985 $ millions)

		Transportation							
Year	Mine	Rail	Terminal	Vessel	Total	Combustion	ESP	FGD*	Total
1985	0	0	0	0	0	0	0	0	0
1986	0	0	0	0	0	0	0	0	0
1987	0	0	0	0	0	0	0	0	0
1988	0	0	0	0	0	0	0	0	0
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	0	0	0	0
1992	0	0	0	0	0	7.0	42.0	45.3	94.3
1993	0	0	0	0	0	7.0	42.0	113.4	162.4
1994	0	0	0	0	0	0	0	249.3	249.3
1995	0	0	0	0	0	0	0	286.0	286.0
1996	0	0	0	0	0	0	0	250.0	250.0
1997	0	0	0	0	0	0	0	250.0	250.0
1998	0	0	0	0	0	0	0	354.0	354.0
1999	0	0	0	0	0	0	0	204.0	204.0
2000	0	0	0	0	0	0	0	0	0

* FGD installed on eight units at Lakeview, four at Lambton and three at Nanticoke.
Sources: Env. Cda and Monenco Ltd.

CAPITAL EXPENDITURES (Cont'd)

Mixed Controls Scenario (1985 $ millions)

		Transportation							
Year	Mine[1]	Rail[2]	Terminal	Vessel	Total	Combustion[3]	ESP	FGD[4]	Total
1985	0	0	0	0	0	0	0	0	0
1986	0	0	0	0	0	0	0	0	0
1987	0	0	0	0	0	0	0	0	0
1988	0	0	0	0	0	0	0	0	0
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	13.0	84.0	0	97.0
1992	0	0	0	0	0	13.0	84.0	0	97.0
1993	0	0	0	0	0	13.0	84.0	45.3	142.3
1994	2.5	29.0	0	0	29.0	7.0	42.0	90.7	171.2
1995	4.1	29.0	0	0	29.0	0	0	158.7	191.8
1996	5.4	0	0	0	0	0	0	181.3	186.7
1997	13.2	29.0	0	0	29.0	0	0	218.0	260.2
1998	41.5	14.5	0	0	14.5	0	0	250.0	306.0
1999	32.3	29.0	0	0	29.0	0	0	100.0	161.3
2000	0	0	0	0	0	0	0	0	0

[1] Minor and major expansions (2 million and 1.3 million tonnes annually, respectively).
[2] Mine additional train set @ $14.5 million each.
[3] Modifications to boiler, coal and ash systems.
[4] FGD installed on four units at Lambton and five units at Lakeview.
Sources: Mine -- EMR; Rail, Terminal, Vessel -- TCda; Combustion -- Monenco Ltd. & Env. Cda; FGD -- Env. Cda & Monenco Ltd.

WCC Control Scenario (1985 $ millions)

		Transportation							
Year	Mine[1]	Rail[2]	Terminal[3]	Vessel[4]	Total	Combustion[5]	ESP	FGD[6]	Total
1985	0	0	0	0	0	0	0	0	0
1986	0	0	0	0	0	0	0	0	0
1987	0	0	0	0	0	0	0	0	0
1988	0	0	0	0	0	0	0	0	0
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1991	0	0	0	0	0	13.0	84.0	0	97.0
1992	0	0	0	0	0	30.5	168.0	0	198.5
1993	0	0	0	0	0	30.5	168.0	0	198.5
1994	9.4	43.5	0	0	43.5	22.0	84.0	0	158.9
1995	58.8	43.5	0	0	43.5	0	0	0	102.3
1996	107.1	58.0	9.0	22.5	89.5	0	0	0	196.6
1997	165.7	29.0	17.0	67.5	113.5	0	0	0	279.2
1998	223.0	58.0	9.0	90.0	157.0	0	0	0	380.0
1999	115.0	58.0	0	45.0	103.0	0	0	0	218.0
2000	0	0	0	0	0	0	0	0	0

[1] Minor expansions (2×10^6 t/yr); major (3×10^6 t/yr) and new mine (5.1×10^6 t/yr).
[2] Twenty additional train sets @ $14.5 million each.
[3] Rail extensions and new unloading equipment.
[4] Five new vessels @ $45 million each.
[5] Modifications to boilers, coal and ash systems.
[6] Precipitators and duct work replaced on eight units at Nanticoke, four at Lambton and two at Lakeview (as part of assumed Lakeview rebuild).
Sources: As for Mixed Controls Scenario.

PRICES FOR U.S. COAL

Item	Assumption	Source
1985	- Cdn $69.45 $54.45 at mine; $15.00 trans.)	- Env. Cda - Alta/Ont. Task Force
Price Escalation	- 1986 to 87 4% per year 1988 to 90 0% per year 1991 + 1% per year (levied on mine price)	- DPA
Exchange Rate (U.S. $1=Cdn.$)	- 1985: $1.3757 - falls steadily to $1.1526 by 1990 - 1990+: $1.1526 (20 year average)	- Statistics Canada DPA in consultation with Env. Cda

- DPA - DPA Group Inc.

U.S. COAL PRICES
(1985 Cdn$/t)

Year	Mine	Transportation	Total Price at OH Gate
1985	54.45	15.00	69.45
1986	50.65	14.50	65.15
1987	47.10	14.00	61.10
1988	45.45	13.55	59.00
1989	43.80	13.05	56.85
1990	42.30	12.60	54.90
1991	42.75	12.60	55.35
1992	43.15	12.60	55.75
1993	43.60	12.60	56.20
1994	44.05	12.60	56.65
1995	44.45	12.60	57.05
1996	44.90	12.60	57.50
1997	45.35	12.60	57.95
1998	45.80	12.60	58.40
1999	46.25	12.60	58.85
2000	46.75	12.60	59.35

PRICES FOR CANADIAN COAL

Item	Assumption	Source
Mine Capital	- $10/t additional annual capacity minor expansion $50/t additional annual capacity major expansion $100/t additional annual capacity new mine - these result in total price at the mine of: $36.50/t minor expansion $42.50/t major expansion $50.00/t new mine	- EMR - DPA in consultation with EMR
Coal Supply Sources	- Mixed Controls (t/yr): 2×10^6 minor expansion 1.3×10^6 major expansion - WCC Control (t/yr): 2×10^6 minor expansion 3×10^6 major expansion 5×10^6 new mine	- EMR
Methodology for Calculating Average Price	- $\Sigma \frac{(\text{price per tonne}_j \text{ x no. tonnes}_j)}{\Sigma \text{ no. of tonnes}}$ (i.e., a weighted average across sources of supply)	- DPA
Annual Prices	- see following tables	

CANADIAN BITUMINOUS COAL PRICES

FGD Control Scenario (1985 $/t)

		Transportation				
Year	Mine	Rail	Terminal	Vessel	Total	Total Price at OH Gate
1985	38.0	40.00	5.75	7.00	52.75	90.75
1986	35.0	40.00	5.75	7.00	52.75	87.75
1987	35.0	40.00	5.75	7.00	52.75	87.75
1988	35.0	36.00	5.75	7.00	48.75	83.75
1989	35.0	36.00	5.75	7.00	48.75	83.75
1990	35.0	36.00	5.75	7.00	48.75	83.75
1991	35.0	36.00	5.75	7.00	48.75	83.75
1992	35.0	36.00	5.75	7.00	48.75	83.75
1993	35.0	36.00	5.75	7.00	48.75	90.75
1994	35.0	36.00	5.75	7.00	48.75	83.75
1995	35.0	36.00	5.75	7.00	48.75	83.75
1996	35.0	36.00	5.75	7.00	48.75	83.75
1997	35.0	36.00	5.75	7.00	48.75	83.75
1998	35.0	36.00	5.75	7.00	48.75	83.75
1999	35.0	36.00	5.75	7.00	48.75	83.75
2000	35.0	36.00	5.75	7.00	48.75	83.75

Status Quo Scenario (1985 $/t)

		Transportation				
Year	Mine	Rail	Terminal	Vessel	Total	Total Price at OH Gate
1985	38.0	40.00	5.75	7.00	52.75	90.75
1986	35.0	40.00	5.75	7.00	52.75	87.75
1987	35.0	40.00	5.75	7.00	52.75	87.75
1988	35.0	36.00	5.75	7.00	48.75	83.75
1989	35.0	36.00	5.75	7.00	48.75	83.75
1990	35.0	36.00	5.75	7.00	48.75	83.75
1991	35.0	36.00	5.75	7.00	48.75	83.75
1992	35.0	36.00	5.75	7.00	48.75	83.75
1993	35.0	36.00	5.75	7.00	48.75	90.75
1994	35.0	36.00	5.75	7.00	48.75	83.75
1995	35.0	36.00	5.75	7.00	48.75	83.75
1996	35.0	36.00	5.75	7.00	48.75	83.75
1997	35.0	36.00	5.75	7.00	48.75	83.75
1998	35.0	36.00	5.75	7.00	48.75	83.75
1999	35.0	36.00	5.75	7.00	48.75	83.75
2000	35.0	36.00	5.75	7.00	48.75	83.75

Sources: Mine — EMR & DPA; Env. Cda
Rail, Terminal, Vessel -- T. Cda

Mixed Controls Scenario* (1985 $/t)

Year	Mine	Transportation				Total Price at OH Gate
		Rail	Terminal	Vessel	Total	
1985	38.00	40.00	5.75	7.00	52.75	90.75
1986	35.00	37.60	5.75	7.00	50.35	85.35
1987	35.00	37.60	5.75	7.00	50.35	85.35
1988	35.00	37.60	5.75	7.00	50.35	85.35
1989	35.00	37.60	5.75	7.00	50.35	85.35
1990	35.00	37.60	5.75	7.00	50.35	85.35
1991	35.00	37.00	5.70	7.00	49.70	84.70
1992	35.00	37.00	5.70	7.00	49.70	84.70
1993	35.00	37.00	5.70	7.00	49.70	84.70
1994	35.00	37.00	5.70	7.00	49.70	84.70
1995	35.00	37.00	5.70	7.00	49.70	84.70
1996	35.20	38.50	4.65	7.00	50.15	85.35
1997	35.30	38.50	4.65	7.00	50.15	85.45
1998	35.40	38.50	4.65	7.00	50.15	85.55
1999	35.80	38.50	4.65	7.00	50.15	85.95
2000	36.70	38.50	4.65	7.00	50.15	86.85

WCC Control Scenario* (1985 $/t)

Year	Mine	Transportation				Total Price at OH Gate
		Rail	Terminal	Vessel	Total	
1985	38.00	40.00	5.75	7.00	52.75	90.75
1986	35.00	37.90	5.75	7.00	50.65	85.65
1987	35.00	37.90	5.75	7.00	50.65	85.65
1988	35.00	37.90	5.75	7.00	50.65	85.65
1989	35.00	37.90	5.75	7.00	50.65	85.65
1990	35.00	37.90	5.75	7.00	50.65	85.65
1991	35.00	37.70	5.55	7.00	50.25	85.25
1992	35.00	37.70	5.55	7.00	50.25	85.25
1993	35.00	37.70	5.55	7.00	50.25	85.25
1994	35.00	37.70	5.55	7.00	50.25	85.25
1995	35.00	37.70	5.55	7.00	50.25	85.25
1996	35.50	39.20	3.65	9.15	52.00	87.50
1997	37.20	39.20	3.65	9.15	52.00	89.20
1998	38.50	39.20	3.65	9.15	52.00	90.50
1999	40.70	39.20	3.65	9.15	52.00	92.70
2000	42.20	39.20	3.65	9.15	52.00	94.20

* Prices include incremental operation and maintenance costs, volume discounts and capital repayment for new investments

Sources: Mine — EMR & DPA; Env. Cda
Rail, Terminal, Vessel -- T. Cda

CANADIAN BITUMINOUS COAL PRICES EXCLUDING CAPITAL RECOVERY FACTORS FOR NEW INVESTMENTS
(1985 $/t)

		Mixed Controls			WCC Control		
Year	Mine	Rail	Terminal	Vessel	Rail	Terminal	Vessel
1985	38.00	40.00	5.75	7.00	40.00	5.75	7.00
1986	35.00	40.00	5.75	7.00	40.00	5.75	7.00
1987	35.00	40.00	5.75	7.00	40.00	5.75	7.00
1988	35.00	36.00	5.75	7.00	36.00	5.75	7.00
1989	35.00	36.00	5.75	7.00	36.00	5.75	7.00
1990	35.00	36.00	5.75	7.00	36.00	5.75	7.00
1991	35.00	36.00	5.70	7.00	36.00	5.55	7.00
1992	35.00	36.00	5.70	7.00	36.00	5.55	7.00
1993	35.00	36.00	5.70	7.00	36.00	5.55	7.00
1994	35.00	36.00	5.70	7.00	36.00	5.55	7.00
1995	35.00	36.00	5.70	7.00	36.00	5.55	7.00
1996	35.00	36.00	4.65	7.00	36.00	3.25	7.00
1997	35.00	36.00	4.65	7.00	36.00	3.25	7.00
1998	35.00	36.00	4.65	7.00	36.00	3.25	7.00
1999	35.00	36.00	4.65	7.00	36.00	3.25	7.00
2000	35.00	36.00	4.65	7.00	36.00	3.25	7.00

Sources: Mine -- EMR, Env. Cda
Rail, Terminal, Vessel -- T. Cda

CANADIAN LIGNITE COAL PRICES: ALL SCENARIOS
(1985 $/t)

		Transportation				
Year	Mine	Rail	Terminal	Vessel	Total	Total Price at OH Gate
1985	14.60	26.00	5.75	0.00	31.75	46.35
1986	14.60	26.00	5.75	0.00	31.75	46.35
1987	14.60	26.00	5.75	0.00	31.75	46.35
1988	14.60	26.00	5.75	0.00	31.75	46.35
1989	14.60	26.00	5.75	0.00	31.75	46.35
1990	14.60	26.00	5.75	0.00	31.75	46.35
1991	14.60	26.00	5.75	0.00	31.75	46.35
1992	14.60	26.00	5.75	0.00	31.75	46.35
1993	14.60	26.00	5.75	0.00	31.75	46.35
1994	14.60	26.00	5.75	0.00	31.75	46.35
1995	14.60	26.00	5.75	0.00	31.75	46.35
1996	14.60	26.00	5.75	0.00	31.75	46.35
1997	14.60	26.00	5.75	0.00	31.75	46.35
1998	14.60	26.00	5.75	0.00	31.75	46.35
1999	14.60	26.00	5.75	0.00	31.75	46.35
2000	14.60	26.00	5.75	0.00	31.75	46.35

Source: Saskatchewan Environment

STATION MODIFICATIONS AND EMISSION CONTROL

Item	Assumption	Source
Combustion Modifications:		
Component Capital Costs	- FGD Control: None - Status Quo: Boiler, coal and ash (2 units @ Nanticoke (N)) - Mixed Controls: Boiler, coal and ash (7 units @ N) - WCC Control: Boiler, coal and ash (8 units @ N; 4 units @ Lambton (Lb)); 2 units as part of assumed schedule rebuild @ Lakeview (Lk))	- Monenco & Env. Cda
Derating	- None	- Monenco
Coal and Ash O&M Costs	- Nanticoke: $360 000/unit - Lambton: $500 000/unit - Lakeview: no incremental costs (rebuild assumed)	- Monenco & Env. Cda
Boiler Mod. O&M Costs	- all stations: no incremental costs	- Monenco & Env. Cda
Precipitators:		
ESP Capital Costs	- $42 million/unit (N & Lb) - no incremental cost at Lakeview (rebuild assumed) - Status Quo: 2 units @ N - Mixed Controls: 7 units @ N	- Monenco
Number of Units Required by the year 2000	- WCC Controls: 8 units @ N, 3 units @ Lb, Lb, 2 units as part of scheduled rebuild @ Lk	- Monenco & Env. Cda
ESP Operating & Maintenance Costs (excl. capital recovery)	- Nanticoke: $460 000/unit - Lambton: $470 000/unit - Lakeview: no incremental costs (rebuild assumed)	- Monenco & Env. Cda
FGD:		
FGD Capital Costs	- Nanticoke and Lambton: $136 000 000/unit - Lakeview: $100 000 000/unit (see Capital Exp. above)	- Monenco
No. FGD units Required by 2000	- FGD Control: 15 (8 units @ N; 4 units @ Lb; 3 units @ Lk) - Status Quo: 15 (8 units @ Lk; 4 units @ Lb, 3 units @ N) - Mixed Controls: 9 (4 units @ Lb; 5 units @ Lk) - WCC Control: None	- Env. Cda
FGD Op. & Main. Costs (excl. capital recovery)	$8 300 000/yr for 500 MW units $6 000 000/yr for 300 MW units	- Env. Cda

CAPITAL RECOVERY FACTORS*
(1985 $ millions)

	FGD Control	Status Quo			Mixed Controls			WCC Controls	
	FGD	FGD	Comb.	ESP	Comb.	ESP	FGD	Combustion	ESP
1985	0	0	0	0	0	0	0	0	0
1986	0	0	0	0	0	0	0	0	0
1987	0	0	0	0	0	0	0	0	0
1988	0	0	0	0	0	0	0	0	0
1989	0	0	0	0	0	0	0	0	0
1990	0	0	0	0	0	0	0	0	0
1991	4.15	0	0	0	1.20	7.95	0	1.20	8.00
1992	14.75	4.15	0.65	3.80	2.40	15.90	0	4.00	23.90
1993	37.60	14.50	1.30	7.60	3.55	23.90	4.15	6.75	39.80
1994	64.45	37.30	1.30	7.60	4.20	27.70	12.45	8.80	47.75
1995	87.35	53.50	1.30	7.60	4.20	27.70	26.95	8.80	47.75
1996	112.20	76.35	1.30	7.60	4.20	27.70	43.55	8.80	47.75
1997	137.10	99.20	1.30	7.60	4.20	27.70	63.50	8.80	47.75
1998	163.25	131.60	1.30	7.60	4.20	27.70	86.35	8.80	47.75
1999	177.00	150.25	1.30	7.60	4.20	27.70	95.50	8.80	47.75
2000	177.00	150.25	1.30	7.60	4.20	27.70	95.50	8.80	47.75

* Calculated as an annuity payment:

$$\text{Capital Expd} = \sum^{N} \frac{\text{capital recovery}_n}{(1 + r)^n}$$

where: r is the interest rate (6.6%)
n is the year; and
N is the amortization period (20 years).

STATION OPERATING COSTS (exluding capital recovery)

FGD Control Scenario
(1985 $ millions)

Year	Combustion	ESP	FGD
1985	0	0	0
1986	0	0	0
1987	0	0	0
1988	0	0	0
1989	0	0	0
1990	0	0	0
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	0	0	16.6
1995	0	0	33.2
1996	0	0	49.8
1997	0	0	66.4
1998	0	0	83.0
1999	0	0	99.6
2000	0	0	117.6

Status Quo Scenario
(1985 $ millions)

Year	Combustion	ESP	FGD
1985	0	0	0
1986	0	0	0
1987	0	0	0
1988	0	0	0
1989	0	0	0
1990	0	0	0
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	0	0	0
1995	0	0	16.6
1996	0	0	33.2
1997	0	0	51.2
1998	0	0	63.2
1999	0	0	81.2
2000	0.7	0.9	106.1

Source: Env. Cda

Mixed Control Scenario
(1985 $ millions)

Year	Combustion	ESP	FGD
1985	0	0	0
1986	0	0	0
1987	0	0	0
1988	0	0	0
1989	0	0	0
1990	0	0	0
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	0	0	0
1995	0.4	0.5	0
1996	0.7	0.9	8.3
1997	1.4	1.8	24.9
1998	1.4	1.8	33.2
1999	2.2	2.8	51.2
2000	2.5	3.2	63.2

WCC Control Scenario
(1985 $ millions)

Year	Combustion	ESP	FGD
1985	0	0	0
1986	0	0	0
1987	0	0	0
1988	0	0	0
1989	0	0	0
1990	0	0	0
1991	0	0	0
1992	0	0	0
1993	0	0	0
1994	0.7	0.9	0
1995	1.4	1.8	0
1996	2.2	2.8	0
1997	2.9	3.7	0
1998	3.4	4.1	0
1999	4.4	5.1	0
2000	4.9	5.6	0

Source: Env. Cda & Monenco Ltd.

EMISSION LEVELS (kt/yr SO_2 and NO_x)

	No Control	FGD Control	Status Quo	Mixed Controls	WCC Control	100% WCC
1985	400	400	400	400	400	400
1986	292	292	281	281	292	281
1987	267	267	247	247	267	247
1988	238	238	208	208	238	166
1989	199	199	163	163	199	81
1990	243	243	210	210	243	93
1991	204	204	182	182	201	83
1992	167	167	150	150	167	70
1993	226	226	174	174	226	77
1994	269	214*	200	200	215	85
1995	323	215	215*	215	215	102
1996	390	215	215	215*	215	118
1997	446	215	215	215	215	134
1998	502	215	215	215	215	148
1999	565	215	215	215	215	163
2000	635	215	215	215	215	181
Total (1985-2000)	5 366	3 740	3 505	3 505	3 738	2 429

*	FGD installed
Source:	Env. Cda

APPENDIX B

ONTARIO HYDRO COAL SUPPLY CONTRACTS

TABLE B.1 SUMMARY OF ONTARIO HYDRO COAL SUPPLY CONTRACTS (as of May, 1985)

		Quantities (kt/max./min.)	
Company	Expiry Date	1986	1991
U.S. Bituminous Coal			
Consolidation Coal Co., WV & PA	Nov. 1991	4535/3628	907/0
Consolidation Coal Co., Bailey Mine, PA	June 1991 (Evergreen)	562/562	1043/771
U.S. Steel Corp., PA	Mine life	2086	2086
Coal Associates, Inc., PA	Dec. 1987 (Evergreen)	544/454	
Eastern Associated Corp., WV	Dec. 1989	816/544	
Oneida Coal Co., WV	Dec. 1987	680/272	
ANR Coal Co., WV	Dec. 1986 (Evergreen)	454/272	
Totals		9678/7818	4036/2857
Western Canadian Bituminous Coal			
Luscar Ltd., Alta.	Dec. 1992	1814/1633	1814/1633
Byron Creek Collieries, B.C.	Dec. 1992	653/590	680/590
Totals		2494/2222	2494/2222
Western Canadian Lignite			
Luscar Ltd., Sask.	Apr. 1996	1111/975	1111/975

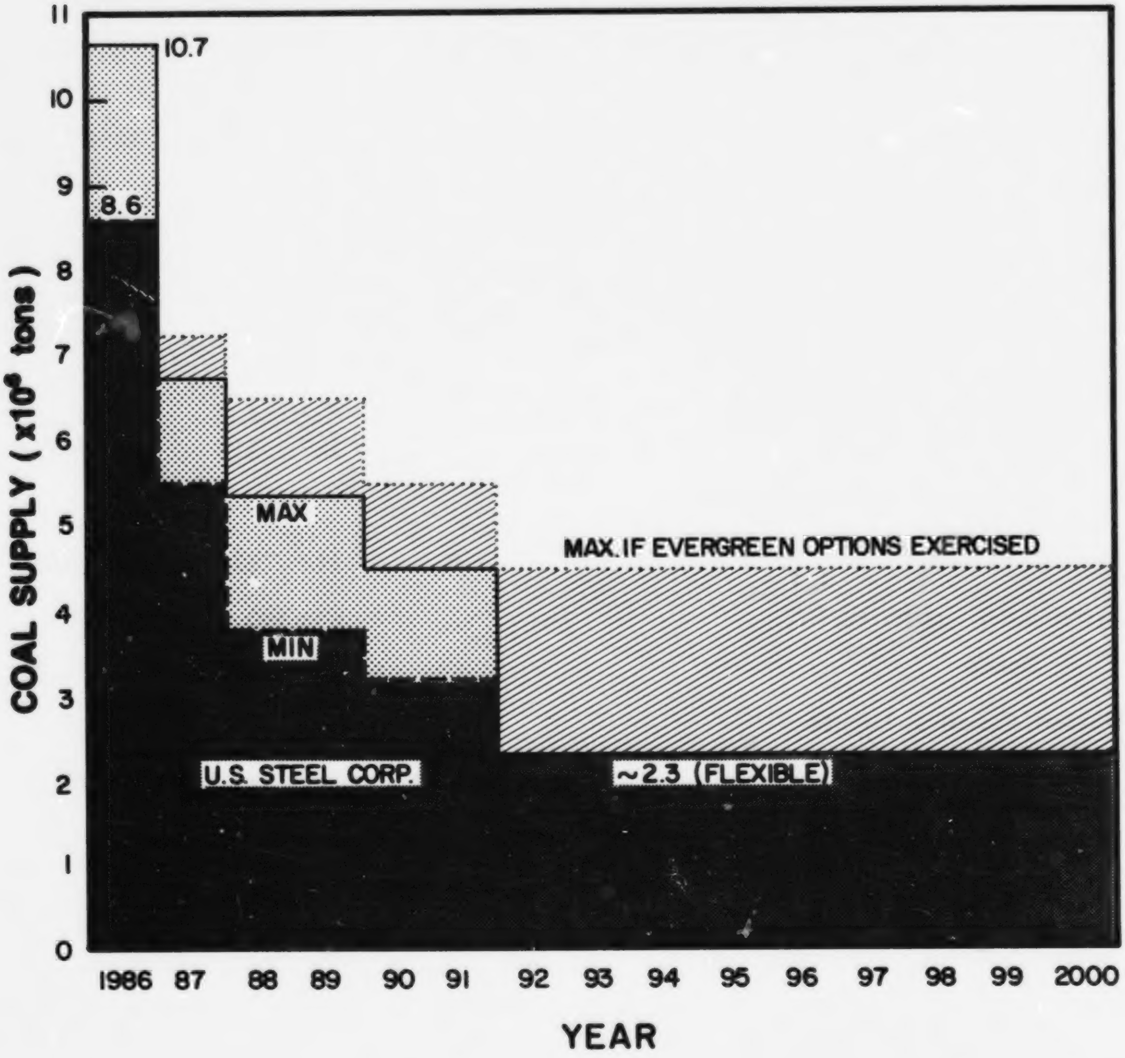

FIGURE B.1 ONTARIO HYDRO U.S. COAL SUPPLY CONTRACTS (May, 1985)

TABLE B.2 ONTARIO HYDRO - U.S. COAL SUPPLY CONTRACTS (as of May, 1985) (kt)

		1986	1987	1988	1989	1990	1991	1992
Consolidation (WV & PA)	Max	4 535	907	907	907	907	907	
	Min	3 628	907	0	0	0	0	
Consolidation (Bailey Mine)	Max	562	1 043	1 043	1 043	1 043	1 043	Evergreen (1 043)-->
	Min	562	771	771	771	771	771	(771)-->
U.S. Steel Corp.	Max(open)	~2 086	~2 086	~2 086	~2 086	~2 086	~2 086	~2 086-->
	Min(open)							
Coal Associates	Max	544	544	(544)	Evergreen (544)	(544)	544	(544)-->
	Min	454	454	(454)	(454)	(454)	(454)	(454)-->
Eastern Associates	Max	816	816	816	816			
	Min	544	544	544	544			
Oneida Coal	Max	680	680					
	Min	272	272					
ANR	Max	454	Evergreen (454)	454	454	454	454	(454)-->
	Min	272	(272)	(272)	(272)	(272)	(272)	(272)-->
Total U.S. (Assuming U.S. Steel provides 2086 t/yr)	Max	9 678	6 077	4 852	4 852	4 036	4 036	2 086
	Min	7 818	5 034	3 401	3 401	2 857	2 857	2 086
	with Evergreen Options Max		(6 530)	(5 850)	(5 850)	(5 034)	(5 034)	(4 127)
	Min		(5 306)	(4 127)	(4 127)	(3 583)	(3 583)	(3 583)

TABLE B.3 ONTARIO HYDRO WESTERN CANADIAN COAL CONTRACTS (as of May, 1985) (kt)

Bituminous		1986	1987	1988	1989	1990	1991	1992
Luscar (Alberta)	Max	1 814	1 814	1 814	1 814	1 814	1 814	1 814
(0.3% S)	Min	1 633	1 633	1 633	1 633	1 633	1 633	1 633
Byron Cr. (B.C.)	Max	680	680	680	680	680	680	680
(0.5% S)	Min	590	590	590	590	590	590	590
Total Bituminous	Max	2 494	2 494	2 494	2 494	2 494	2 494	2 494
	Min	2 222	2 222	2 222	2 222	2 222	2 222	2 222
Lignite								
Luscar (Sask.)	Max	1 111	1 111	1 111	1 111	1 111	1 111	1 111-->(to 1996)
(0.6% S)	Min	975	975	975	975	975	975	975-->

APPENDIX C

SOCIOECONOMIC IMPACT DATA

APPENDIX C SOCIOECONOMIC IMPACT DATA

Tables C-1, C-2 and C-3 provide details of the factors and multipliers used to calculate direct, indirect, and induced employment and GDP effects of the four coal use scenarios.

TABLE C-1: Value Added as Percent of Total Income; Salaries and Wages as a percent of Value-Added; Average Annual Wages by Industry

Estimates of value added as a percent of income were derived from Corporation Financial Statistics (Statistics Canada Catalogue 61-207, 1982) for each industry and supplier industry (for indirect percentages).

Combined direct, first order indirect, and second order indirect percentages were calculated as the total value added generated per $100 direct income.

Estimates of total wages and salaries by industry are calculated from value added based on corporation financial statistics by industry. Wages and salaries are divided by average wages to determine employment (direct and indirect), and are used as input to determine induced GDP and employment effects. Average wages were derived from Employment, Earnings and Hours (Statistics Canada Catalogue 72-002, November, 1984), and adjusted for inflation and employer-paid benefits.

TABLE C-2: Induced Employment Generated from (1985) $10 Million in Wages and Salaries

The factors shown in Table C-2 were derived from Statistics Canada Input-Output Tables (1979). Factors from Statistics Canada were converted from a 1979 to 1985 dollar basis by applying an inflation factor (CPI) of 0.634. Derived factors were multiplied by estimates of generated wages and salaries (transfers to persons) by province to produce estimates of induced employment by province.

TABLE C-3: Induced GDP Generated from (1985) $10 Million Increase in Wages and Salaries

The factors presented in Table C-3 were derived from Statistics Canada Input-Output Tables (1979) in the same manner as employment factors. GDP factors are applied to generated wages and salaries (transfers to persons) by province to produce estimates of incremental provincial GDP.

TABLE C-1 VALUE ADDED AS A PERCENTAGE OF TOTAL INCOME: SALARIES AND WAGES AS A PERCENTAGE OF VALUE ADDED: AVERAGE ANNUAL WAGES BY INDUSTRY

	Value Added as Percent of Total Income	Salaries and Wages as Percent of Value Added	Average Annual Wages ($ 1985)*
Rail Transport			
direct	52.9	71.0	37 300
1st indirect	30.0	70.0	33 000
2nd indirect	30.0	70.0	33 000
combined	76.9	70.7	35 957
Water Transport			
direct	48.6	59.8	50 000
1st indirect	30.0	70.0	33 000
2nd indirect	30.0	70.0	33 000
combined	74.8	63.4	44 043
Coal Handling			
direct	56.6	44.7	27 300
1st indirect	30.0	70.0	33 000
2nd indirect	30.0	70.0	33 000
combined	78.7	51.8	28 902
Engineering and Scientific Services			
direct	50.6	78.2	38 200
1st indirect	30.0	70.0	33 000
2nd indirect	30.0	70.0	33 000
combined	75.8	75.5	36 472
Building Contractors			
direct	20.2	77.2	32 000
1st indirect	47.2	66.6	34 500
2nd indirect	30.0	70.0	33 000
combined	70.5	55.5	33 515
Railroad Rolling Stock			
direct	41.0	41.0	36 000
1st indirect	35.0	75.0	35 000
2nd indirect	30.0	70.0	33 000
combined	73.2	70.2	35 426

TABLE C-1 VALUE ADDED AS A PERCENTAGE OF TOTAL INCOME: SALARIES AND WAGES AS A PERCENTAGE OF VALUE ADDED: AVERAGE ANNUAL WAGES BY INDUSTRY (Cont'd)

	Value Added as Percent of Total Income	Salaries and Wages as Percent of Value Added	Average Annual Wages ($ 1985)*
Shipbuilding			
direct	55.6	66.8	37 800
1st indirect	35.0	75.0	35 000
2nd indirect	30.0	70.0	33 000
combined	79.8	68.7	36 734
Highway and Bridge			
direct	34.7	68.0	32 000
1st indirect	35.0	75.0	35 000
2nd indirect	30.0	70.0	33 000
combined	70.3	70.6	33 157
Other (non-electrical)			
direct	33.7	70.7	34 400
1st indirect	35.0	75.0	35 000
2nd indirect	30.0	70.0	33 000
combined	69.8	72.0	34 340
Motor Vehicles			
direct	14.4	80.9	43 800
1st indirect	30.0	70.0	33 000
2nd indirect	30.0	70.0	33 000
combined	58.1	72.7	35 679
Electrical Industrial Equipment			
direct	35.3	74.8	32 500
1st indirect	30.0	70.0	33 000
2nd indirect	30.0	70.0	33 000
combined	68.3	72.5	32 742
Metal Fabricating			
direct	34.4	73.1	30 600
1st indirect	30.0	70.0	33 000
2nd indirect	30.0	70.0	33 000
combined	67.9	71.6	31 783

TABLE C-1 VALUE ADDED AS A PERCENTAGE OF TOTAL INCOME: SALARIES AND WAGES AS A PERCENTAGE OF VALUE ADDED: AVERAGE ANNUAL WAGES BY INDUSTRY (Cont'd)

	Value Added as Percent of Total Income	Salaries and Wages as Percent of Value Added	Average Annual Wages ($ 1985)*
Petroleum Refineries			
direct	17.5	30.1	49 100
1st indirect	54.4	9.9	53 100
2nd indirect	30.0	70.0	33 000
combined	80.0	20.7	50 074
Electric Power			
direct	73.2	28.3	45 600
1st indirect	30.0	70.0	33 000
2nd indirect	30.0	70.0	33 000
combined	86.9	34.9	43 617
Industrial Chemicals			
direct	25.5	50.7	44 400
1st indirect	30.0	70.0	33 000
2nd indirect	30.0	70.0	33 000
combined	63.5	62.2	37 578
Special Trade Contractors			
direct	47.2	66.6	34 500
1st indirect	35.0	75.0	33 000
2nd indirect	30.0	70.0	33 000
combined	76.0	69.1	33 932
Coal Mines			
direct	47.6	56.9	51 400
1st indirect	35.0	75.0	33 000
2nd indirect	30.0	70.0	33 000
combined	76.2	63.0	44 500

Sources: Statistics Canada
Catalogue 61-207 Corporation Financial Statistics (1982).
Catalogue 72-002 Employment, Earnings and Hours (November, 1984).

Note:* Average Annual Salary was Calculated as:
November 1984 August Weekly Earning x 52 x 1.02 x 1.25
where: 1.02 = inflation adjustments to 1985 $
1.25 = adjustments for employer paid benefits.

TABLE C-2 INDUCED EMPLOYMENT GENERATED FROM (1985) $10 MILLION INCREASE IN WAGES AND SALARIES (person-years)

Province of Expenditure	Province of Employment Generation B.C.	Alberta	Saskatchewan	Ontario	Other Canada
B.C.	145.2	16.5	2.5	41.8	29.2
Alberta	17.1	114.1	3.8	48.2	35.5
Saskatchewan	12.0	17.1	97.6	56.4	48.2
Ontario	4.4	6.3	1.9	154.7	38.0
Other Canada					
Manitoba	10.8	12.0	7.0	56.4	230.8
Quebec	4.4	7.6	1.9	50.1	164.8
Nova Scotia	5.1	5.1	2.5	68.5	201.6

TABLE C-3 INDUCED GDP GENERATED FROM (1985) $ 10 MILLION INCREASE IN WAGES AND SALARIES (1985) ($ thousands)

Province of Wages and Salaries Received	Province of Employment Generation B.C.	Alberta	Saskatchewan	Ontario	Other Canada
B.C.	632	120	16	171	117
Alberta	82	555	23	196	141
Saskatchewan	57	132	466	230	191
Ontario	22	62	14	629	157
Other Canada					
Manitoba	53	98	43	234	649
Quebec	21	64	16	211	669
Nova Scotia	23	40	16	279	799

Source: Statistics Canada Input-Output Tables (III. A. 1-11 1979).

APPENDIX D

DESCRIPTION OF ENVIRONMENTAL EFFECTS

APPENDIX D DESCRIPTION OF ENVIRONMENTAL EFFECTS

D.1 Coal Mining

Open-pit mining is characterized by the excavation of steep-sided benches and the creation of one or more deep pits from which soil and rock overburden are removed, exposing the coal. Soil/rock overburden is broken by explosives to manageable sizes, then removed by truck to waste rock dumps situated along mountain sides or in previously worked pits. The volume of overburden to be removed depends on the depth to the coal seam(s), which can be up to 100 m. In western Canada, open-pit mines are between 50 m and 70 m deep. Once the coal seam is exposed, explosives may be used to break the coal which is loaded and hauled to a preparation facility for cleaning.

Open-pit mining affects land, water, and air components of the environment.

(a) Land. The main impact on land occurs during the mining and waste disposal stages of coal extraction, when rock overburden is removed. The amount of material removed depends on the stripping ratio (defined as the unit weight of waste rock or overburden removed per unit weight of coal extracted). On an overburden/tonne coal basis, stripping ratios are likely to range from 5:1 to 15:1 (i.e., 5 to 15 tonnes waste rock or overburden per tonne of coal). A ratio of 10:1 can be assumed for the purpose of this study.

Other land surface area is disturbed for waste rock disposal area requirements, coal stockpile and load out facilities, and areas for buildings and equipment. For estimation purposes, a ratio of 30 ha per million tonnes of coal mined can be assumed for total surface area disturbance.

Damage to vegetation, removal of habitat, and alteration of (surface) topography will adversely affect animal populations. As a result, wildlife may have to migrate to other areas. The aesthetics of the region may be permanently changed with open-pit mining, although it is difficult to assess or quantify these changes beyond a qualitative description.

(b) Water. For mines located below the water table or where the coal seam is itself an aquifer, dewatering is required before mining can proceed. Dewatering water may be contaminated with trace elements so that release of large volumes to natural surface water systems could degrade surface water quality. Dewatering volumes can range up to 10 m^3/t of coal removed.

Open-pit mines also produce wastewater resulting from surface runoff, direct precipitation, and groundwater infiltration into the pit from joints and fractures in the overburden. Wastewater production is seasonal, mostly occurring during spring runoff (April-May) and fall rains (October).

Mine drainage water may contain trace elements (Al, As, B, Fe, Mn, Ti, Zn) and inorganic constituents (NO_3, SO_4, Cl^-, TDS, TSS), and requires treatment in site settling ponds if levels exceed regulatory standards. For mines located in areas where net evaporation exceeds precipitation, there is little or no direct discharge from the settling ponds, although seepage to groundwater may occur. Due to the commonly low pyrite (FeS_2) content of western Canadian bituminous coal, the generally dry environment, and the presence of calcareous bedrock adjacent to the coal seams, acid mine drainage is not expected to be a problem.

Mine wastewaters may contain levels of nitrate-nitrogen (NO_3-N) sufficiently high to accelerate eutrophication in surface waters. NO_3-N originates from unburned nitrogen-based blasting agents such as ammonium nitrate fuel oil (ANFO) used for overburden removal. The ammonium ion (NH_4^+) is biologically converted to nitrate (NO_3^-).

High levels of suspended solids in runoff from stripping wastes and mine site surface areas can cause stream siltation and habitat damage. Elevated hardness and high concentrations of such soluble inorganic constituents as Ca, Fe, SO_4, and CO_3 can impair the quality of local surface waters for other uses. Consequently, provincial regulations are in force which require mine operators to collect and sometimes treat mine water and surface runoff in settling basins prior to discharge to local water bodies.

(c) Air. Air pollution from open-pit mining is not as severe as combustion-related effects. There are, however, areas where air degradation can occur.

First, fugitive or windblown dust from loading points, coal stockpiles, and waste disposal sites may cause air pollution. Vehicular traffic on the site will also create localized dusting on roadways and at the pit face. A factor of 2 kg/t of coal removed can be used to approximate fugitive dust emissions from open-pit mines in the foothills area of Alberta and British Columbia.

Second, emissions from diesel powered equipment (such as power shovels, bulldozers, loaders, and trucks) may create localized sources of air pollution. These emissions contain known carcinogens and are considered potentially harmful in poorly ventilated environments. With sufficient ventilation, as in open-pit mining, the effect is minimal, although with greater depth below the surface, wind movement is significantly reduced.

Due to the isolated locations of the Alberta and B.C. mines in the foothills and mountain regions, air pollution problems are not expected to affect adjacent communities.

D.2 Coal Preparation

The main purpose of coal preparation is the removal of inorganic sulphur compounds (FeS_2, SO_4^{2-}) and mineral matter (clays and shale) from thermal and metallurgical coals. In general, metallurgical coals (usually medium volatile and low volatile bituminous coal) have more stringent limits for sulphur than thermal coals and, therefore, require cleaning. Certain bituminous thermal coals may also require cleaning to reduce ash content and increase unit calorific value.

Coal preparation processes rely on the relative differences in size, specific gravity, and surface properties of raw coal to achieve separation of coal from the ash and pyritic impurities.

Coal preparation can be divided into physical (mechanical) and chemical processes. Currently, all preparation plants in Canada rely on the former process. Specific gravity separation is the most widely used method. Chemical coal cleaning, currently in the research stage, may be developed later. Conventional physical coal cleaning techniques are expected to prevail until at least 1995. Cleaning may be required to reduce ash content, increase calorific value, and reduce transport costs of western bituminous thermal coal shipped eastward.

Coal preparation plants generate solid, liquid, and gaseous wastes that may adversely affect the environment. Actual effects depend on the volumes and toxicity of the wastes generated which, in turn, depend on coal characteristics and the size throughput of the preparation plant.

(a) Solid Wastes. Preparation plants produce three sizes of solid wastes: coarse, intermediate, and fine. The relative proportion of a given size of solid waste produced depends on the preparation process used (wet or dry); the mining process used, the efficiency of the coal cleaning process(es) used; and the requirements of the product coal.

Average total refuse production is about 30% of the mined feed material, with the combined volumes of coarse and intermediate refuse exceeding that of fine refuse by two-fold or more.

Coarse refuse consists of large rock fragments, wood, and metallic particles removed from the raw coal before the crushing process, and waste rock liberated during the crushing and primary screening operations. Coarse refuse ranges from 10 to 30 cm in size, and may contain a significant proportion of coal attached to the waste rock fragments. The quality of coarse refuse depends on its mineralogical components (e.g., shale, sandstone, limestone, sand, gravel, silt, clay, and sub-grade coal). In turn, the mineralogical components determine physical/chemical breakdown and subsequent leaching. Due to concentration of non-carbonaceous constituents in refuse, under certain conditions they may be leached in sufficient quantities to cause adverse environmental effects.

During preparation, the refuse/water slurry, containing both intermediate-and fine-sized refuse is fed to clarifiers to separate the intermediate sized material from the fine. Intermediate refuse is dewatered and combined with coarse refuse. Fine refuse is dewatered in thickeners and pumped to tailings or slurry ponds.

(b) Air Emissions. The major air effects of coal preparation are fugitive dust (particulate) emissions originating at several points within the site, particulate and gaseous emissions from coal drying facilities, and gaseous emissions from coarse refuse piles. Sources of fugitive dust are:

- coarse refuse piles (active and unreclaimed),
- dry slurry pond surfaces,
- plant site roads,
- coal storage piles and load out facilities, and
- dry crushing and screening plants.

The amount of dust generated from these sources depends on the surface area involved and climatic factors such as wind speed, precipitation, and humidity.

The final stage in coal preparation involves drying the clean coal from a moisture content of 20% to about 8%. Excess moisture is removed from the coal by passing heated air (generated from burning either coal or natural gas) through the coal bed as it moves on a conveyor system. Fluid bed drying systems are conventionally used.

Due to the nature of the process, with passage of heated air through the bed, thermal drying may affect air quality by releasing sulphur oxides, nitrogen oxides, carbon monoxide, particulate matter, and hydrocarbons.

Coarse refuse piles containing sulphur particles may undergo spontaneous combustion when temperature increases caused by wetting sulphide (by precipitation) are not released or dissipated. The temperature increase is sufficient to sustain incomplete combustion, which can result in the release of potentially toxic gases from the piles. Gaseous emissions include particulate, hydrocarbons, carbon monoxide, nitrogen oxides, sulphur oxides, and polycyclic organic matter. Although no burning refuse piles are known to exist in Canada, increases in mining and waste rock production may lead to future burning of coarse refuse piles, creating significant local air pollution problems.

(c) Water Use and Supply. Water is used in the mining and preparation of bituminous coal for dust control in mines and on haulage roads, coal washing in the preparation plants, equipment washdown and sanitation. Available data indicates that water withdrawal rates for mines in B.C. and Alberta range from 0.3 to 0.7 m^3/t of production. Both surface and groundwater sources provide the water required to mine and beneficiate coal in this region. Water supplies in B.C. and Alberta are plentiful and competition for water by other sectors is minimal.

As lignite is not subjected to wet preparation, withdrawals from surface water sources are primarily for dust control, equipment washdown and sanitary use. Although total volumes withdrawn are low when compared with those required to produce bituminous coal, due to the location of the lignite mines in southern Saskatchewan where water supplies are short and evaporative losses are high, future competition for this resource by other sectors of the economy may become significant.

Water withdrawals are (roughly) estimated as 0.7 m^3/t and 0.1 m^3/t for bituminous coal and lignite mining, respectively; and 0.5 m^3/t for preparation of bituminous coal.

(d) Liquid Wastes. Since coal cleaning is generally conducted in an aqueous medium, it is inevitable that preparation plants will generate water which, if discharged untreated to natural surface water systems, may degrade the aquatic environment. Although preparation plants in B.C. and Alberta practice 100% recycling of process water and therefore, in theory, no preparation plant wastewaters are discharged, quantities of contaminated water can enter the environment as seepage into local groundwater systems from unlined tailings lagoons and as seepage and uncontrolled runoff from plant site areas, coal storage piles, and coarse refuse disposal piles. The possible accumulation of chemical reagents in preparation plant recycle waters, which could adversely affect coal washing processes, may also require periodic discharge to the environment.

Coal preparation plant effluents contain several contaminants:

Trace elements: Since coal contains several metallic (e.g., Al, As, Sb, Te) and non-metallic (e.g., S, N, C) elements, the ultimate source of trace elements in preparation plant wastewater is the coal itself. After removal from the seam, coal oxidation:

- increases friability of the coal; and
- produces humic acids, releasing metallic elements from the coal.

Certain trace elements, such as Cd, Hg, Pb, are acutely toxic; others, such as Al, As, Cu, Ni, Zn, are less toxic, but still represent an environmental problem if discharged in high concentrations.

Inorganic compounds: Coal is also the main source of several inorganic compounds such as CO_3^{2-}, SO_4^{2-}, NO_3, C^-. Suspended solids and dissolved solids may be present in preparation plant discharges due to the physically abrasive nature of preparation methods. Effluents from preparation plants may present a hazard if discharged in an untreated form to the environment. Although the toxicity of inorganic ions is less than the toxicity of certain metallic ions, high levels of suspended solids in effluent may adversely affect aquatic life.

Organic compounds: Coal is often regarded as metamorphosed organic rock because coal evolves from the deposition and thermal alteration of organic compounds. Consequently, it is a potential source of several organic compounds. Surface oxidation of the coal, with resultant humic acid production, may also result in possible leaching of organic compounds. The use of organic flotation reagents such as kerosene and fuel oil may further increase the solution of organic compounds from coal, increasing effluent concentrations.

Chemical cleaning of coal and other advanced cleaning technologies using solvents, bacteria, and leaching operations for both inorganic and organic sulphur removal may release organic compounds from the coal matrix. These compounds may be further transformed by certain cleaning operations such as hydro-thermal leaching (involving high temperature and pressure) into potentially harmful compounds.

D.3 Transportation (Rail, Vessels, Terminals)

(a) Rail. Primary environmental, health and safety concerns associated with transporting coal by rail are:

- fugitive dust blown from coal cars;
- diesel emissions from locomotives;
- fires caused by sparks from wheel/rail contact;
- noise from trains passing through communities; and
- hazards at highway/railway crossings.

At the existing level of coal transport to Ontario, few complaints have been received with respect to fugitive dust along the route. The increased rail traffic required to meet expanded western Canadian coal use scenarios could compound any problems and lead to public complaint.

A dust emission factor of 0.005 kg/t·km is commonly used for estimating fugitive dust emissions from coal cars without dust control. Sealant sprays reduce these emissions by approximately 95%.

All coal mines in western Canada currently shipping coal by unit train over long distances are equipped with spray apparatus to coat coal with chemical sealants. A conservative estimate of the cost of this treatment is $10/car. The capital cost for a sealant spray system is estimated at $250 000 to $300 000. Overall system costs for sealant spray apparatus installation and operation are estimated at between $0.16 and $0.34/t of coal transported.

In spite of dust control systems, fugitive coal dust blown from unit coal trains is a pollution problem in communities along the southeast B.C. rail corridor from Kamloops to Vancouver.

If fugitive dust problems persist in spite of sealant spray operations, automated coal covers to eliminate dusting would have to be considered. This form of dust control is more effective, but more costly, than sprays. Estimates of automated coal car cover system costs range from $0.57 to $1.31/t of coal transported.

Diesel emissions from trains have not been identified as an environmental problem, although individual complaints concerning diesel fumes have been registered. Any adverse effects of diesel fuel combustion will increase in proportion to the increase in unit coal train activity. Pooled diesel engines running at idle, especially during winter months, can be the source of public complaint.

In the hot, dry summer months, numerous grass and brush fires are started from sparks from rails, particularly across the prairies. As rail traffic increases, fires will likely become more frequent, increasing risk to communities along the rail lines and, consequently, costs of firefighting equipment and manpower.

East-west rail lines pass through many villages and towns. A substantial increase in the frequency of long, high speed freight trains passing through these communities, particularly during the night, may be of concern to residents.

There are many hundreds of crossings along the rail routes from Alberta and B.C. Again, increased rail traffic could lead to more accidents with motor vehicles and increased traffic flow problems in urban communities.

(b) Vessels. Combustion emissions from vessels have not been identified as an environmental problem. Since all coal carried in lakers or ocean-going vessels is in enclosed or covered holds, fugitive dusting enroute should not occur.

A handling loss emission factor of 0.1% is commonly used to estimate coal cargo spillage during vessel loading and unloading. Coal spilled on the decks of colliers is normally washed overboard. Fine particles in western Canadian coal will float and can wash ashore and cause beach pollution. One incident of this nature was reported in the Strait of Georgia in 1984. Coal settling on harbour bottoms may also cause damage in environmentally sensitive areas.

The seriousness of dusting and product spillage during vessel loading and unloading operations is currently being investigated by Environment Canada. Cost-effective mitigation measures are also being investigated.

(c) Terminals. The Thunder Bay coal terminal has water collection, recycle, and treatment facilities along with pile sprays and other dust control equipment. Any new coal or expanded terminal facility must be equipped with similar or updated control equipment.

The three major west coast coal terminals have installed a variety of dust/water pollution control equipment. Existing problems, particularly at Prince Rupert and Roberts Bank, include fugitive dusting from storage piles during high winds. Pile sprays are employed and operations are suspended during severe winds.

Large coal storage piles may cause problems due to wind and runoff that do not exist at the present storage levels, particularly at Thunder Bay during winter freeze-up.

Dusting from coal not dumped from "empty" returning cars have caused public complaints (e.g., Vancouver terminals). Increased coal/rail traffic will add to the existing problems. There are at present no cost-effective mitigation measures for this pollution problem, although solutions are under investigation.

D.4 Combustion

The suggested scenarios for expanded use of western Canadian coal by Ontario Hydro would not increase the quantities of electricity generated by coal-fired stations in Ontario.

Some of the concerns common to coal-fired stations, such as the cooling water system, water treatment plant wastes, and equipment cleaning would not significantly change. The major environmental differences in switching from U.S. to western Canadian coal would be in the following areas:

- coal storage and handling,
- ash disposal,
- FGD waste disposal, and
- air emissions.

(a) Coal Storage and Handling. Due to its lower heat content, approximately 20% more western coal would be required to produce the same amount of electricity as U.S. coal. In addition, for scenarios where coal is blended, separate coal docks and separate coal storage areas would be required for western Canadian and U.S. coals. Additional space would also be needed for coal blending.

Increased coal volumes and larger storage and handling areas would increase fugitive dust and runoff problems, which could increase expenses for dust control and coal pile runoff treatment facilities. Due to the lower sulphur content of western Canadian coals, however, runoff is not expected to be acidic and trace metals and other constituents will not leach as readily as from U.S. coal. Coal pile wastewater quality from western Canadian coals is, therefore, likely to be better than from U.S. coal.

(b) Ash Disposal. Western Canadian bituminous coal has (on average) about 21% more ash than U.S. bituminous coal (assuming ash contents of 11.9% and 9.8% for Canadian and U.S. coals, respectively). Combined with a 20% increase in western Canadian coal quantities (to produce the same amount of electricity), this implies that approximately 46% more ash would be produced with western Canadian bituminous coal.

Certainly, significantly larger ash lagoons or land disposal areas and increased ash transport capacity would be required under the WCC Control option. It is assumed that the three major Ontario Hydro stations involved would use dry fly ash disposal. (Nanticoke now uses a once-through wet lagoon system involving the discharge of large quantities of ash transport wastewater.) Bottom ash would be dewatered in dewatering bins at the station prior to being mechanically transported to a landfill. The major environmental concerns with this kind of system would be larger landfill areas leading to increased runoff and seepage volumes.

(c) FGD Waste Disposal. Increased use of western Canadian coal would decrease the amount of FGD equipment required to meet Ontario acid gas emission limits. If sufficient western Canadian coal were used, the limits would be met without any FGD. This would eliminate environmental concerns associated with disposal of the large quantities of solid wastes produced by FGD systems, including land requirements, related runoff and process wastewater discharges.

FGD sludge volumes at a station burning a low sulphur, low heating value, high ash content coal add only marginally to the station's already large solid waste production volume. With higher sulphur, low ash coals, however, the FGD system may produce substantially more solid waste in absolute terms and a two-fold increase in the station's total solid waste production.

Wastewaters from FGD systems originate directly from the scrubbing process and from runoff and seepage from the disposal areas. FGD systems can be designed for zero direct wastewater discharge (Environment Canada, 1985).

Some wet FGD processes, however, may blowdown to control chloride and fluoride concentrations, or wastewater from wet FGD systems may overflow.

It is difficult to estimate the quantities of direct wastewater discharge that might be produced annually from upset conditions at a wet FGD installation. A rough approximation of the range of direct wastewater discharge volumes that might be expected from a wet FGD at a 1000 MW facility is 0 to 40 000 m^3/yr. At stations using western Canadian bituminous coal or a western Canadian-U.S. coal blend, a spray drier FGD system may be feasible. With such systems, process wastewater is not generated and a dry waste product is produced from the scrubber.

Because of the very large areas required by some non-regenerable FGD systems for the disposal of sludges, the largest wastewater volumes may be runoff and seepage from the disposal area. Runoff and seepage volumes tend to increase proportionally with sludge volumes, but depend on many factors including disposal method (dry landfill versus lagoon), sludge characteristics, and permeability of underlying soils. A rough approximation of the range for FGD related seepage and runoff wastewater for a 1000 MW station is:

Seepage	0 to 750 000 m^3/yr
Runoff	0 to 120 000 m^3/yr

Although the characteristics of FGD related wastewaters can be highly variable depending on type of system, coal characteristics, and source of wastestream, they may have high dissolved solids, sulphate, and chloride contents. Some also have elevated levels of trace contaminants such as Al, B, Mo, Ni, and As.

Runoff and seepage wastewater characteristics depend on the characteristics of the waste. These, in turn, depend on the coal, FGD process, and waste stabilization or fixation process (if any).

(d) Air Emissions. Air emissions from coal-fired stations emanate from stack emission of combustion byproducts, from windblown fugitive dust arising from coal storage piles, coal and ash handling operations, exposed surfaces in ash disposal areas, and from the operation of equipment and vehicles around the plant.

In the immediate vicinity of the station (within 5 to 10 km), deposition from fugitive dust emissions can far exceed the deposition from stack particulate emissions. As previously indicated, these emissions are likely to increase with increased use of western Canadian coal due to the larger coal storage and ash disposal areas and increased handling requirements for both coal and ash.

Stack emissions contain both conventional pollutants -- particulate, SO_2 and NO_x -- and a variety of trace substances, including trace metals and hydrocarbons. The released substances are dispersed into the atmosphere and deposited in a pattern dependent on the stack height, emission rate, and prevailing atmospheric conditions. The areas of greatest annual deposition are often within 5 to 30 km of the station, but portions of the emitted materials are transported over hundreds of kilometres and deposited over a wide area.

The expanded use of western Canadian bituminous coal will affect the release of both conventional pollutants and trace substances. Release of conventional pollutants is likely to change as follows:

Particulate. With an estimated 46% increase in total loading, particulate emissions can be expected to increase by 46% if new electrostatic precipitators (ESP) capable of achieving the same removal efficiencies as existing ESPs on U.S. coal are installed. To keep particulate emissions to current levels, the new ESPs would have to achieve better removal efficiency than those now being used.

Sulphur Dioxide (SO_2). Since western Canadian bituminous coal contains only about 13% of the sulphur contained in Appalachian coal, substantial reductions in SO_2 emissions would be realized. Even after adjusting for the increased coal quantities needed, uncontrolled SO_2 emissions with western Canadian coal would be only 16% of those from U.S. coal.

Nitrogen Oxides (NO_x). Since NO_x emissions are estimated on a heat input basis (i.e., kg/kJ), they are essentially the same whether western Canadian or U.S. coal is burned.

SO_2 and NO_x are the primary contributors to acid precipitation in Eastern Canada. The adverse effects of the resulting acid precipitation on terrestrial and aquatic ecosystems, particularly in the poorly buffered terrain of Eastern Canada, are well documented.

Trace constituent emissions are dependent on their concentrations in the coal. Trace metal concentrations can vary significantly, not only from one coal type to another, but also among similar coal types from different mines and from one seam to another. Trace constituent emissions from combustion, therefore, could be quite different from western Canadian and U.S. coals. Typically, western Canadian bituminous coals from the foothills areas of Alberta and B.C. tend to be lower in arsenic, chromium, cobalt, mercury, molybdenum, and nickel, but higher in barium, boron, thorium, and uranium than imported U.S. coals.